PB-223 148

FIELD INVESTIGATION OF EMISSIONS FROM COMBUSTION EQUIPMENT FOR SPACE HEATING

Battelle Columbus Laboratories

Prepared for
Environmental Protection Agency

June 1973

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PB 223 148

EPA-R2-73-084a

(API Publication 4180)

June 1973

Environmental Protection Technology Series

Field Investigation of Emissions from Combustion Equipment for Space Heating

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NATIONAL TECHNICAL
INFORMATION SERVICE
U.S. Department of Commerce
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American Petroleum Institute
1801 K Street, NW
Washington, D.C. 20006

Office of Research and Monitoring
U.S. Environmental Protection Agency
Washington, D.C. 20460

210

BIBLIOGRAPHIC DATA SHEET

1. Report No. EPA-R2-73-084a

2.

3. Recipient's Accession No. PB-223 148

4. Title and Subtitle
Field Investigation of Emissions from Combustion Equipment for Space Heating

5. Report Date June 1973.

6.

7. Author(s)
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8. Performing Organization Rept. No.

9. Performing Organization Name and Address
Battelle - Columbus Laboratories
505 King Avenue
Columbus, Ohio 43201

10. Project/Task/Work Unit No.

11. Contract/Grant No.
68-02-0251

12. Sponsoring Organization Name and Address
EPA, Office of Research and Development
NERC-RTP, Control Systems Laboratory
Research Triangle Park, North Carolina 27711

13. Type of Report & Period Covered
Final

14.

15. Supplementary Notes

16. Abstracts

The report gives results of a 2-year field investigation of air-pollutant emissions from 33 residential heating units and 13 commercial boilers. It includes effects of combustion parameters and fuel-oil compositions, as well as measurements of CO, HC, NOx, SO2, particulate, and smoke. The largest residential emissions reduction resulted from replacing poorly performing units.
Burners with flame-retention combustion heads had lower overall emissions than those with conventional heads; newer burners had lower emissions than older ones. Emission from commercial boilers (40-600 boiler hp) were measured for 33 combinations of boilers and fuels at various loads and excess air settings. Generally, operating parameters within the normal adjustment range had minor effect on emissions. Fuels investigated were natural gas and five grades of fuel oil, including a 1%-S residual oil. Fuel characteristics significantly affected emissions, especially particulate and NOx. For oil firing, NOx emissions increased nearly linearly with fuel-N content.

17. Key Words and Document Analysis. 17a. Descriptors

Air Pollution
Space Heating
Residential Buildings
Commercial Buildings
Combustion
Emission
Burners
Boilers
Furnaces
Nitrogen Oxides
Nitrogen Oxide (NO)
Nitrogen Dioxide
Particulate Composites
Smoke
Carbon Monoxide
Hydrocarbons
Sulfur Oxides
Sulfur Dioxide
Sulfur Trioxide
Natural Gas
Fuel Oil

17b. Identifiers/Open-Ended Terms

Air Pollution Control
Stationary Sources
Emission Factors
No. 2 Oil
No. 4 Oil
No. 5 Oil
No. 6 Oil

17c. COSATI Field/Group 13B, 7C

18. Availability Statement
Unlimited

19. Security Class (This Report)
UNCLASSIFIED

20. Security Class (This Page
UNCLASSIFIED

21. No. of Pages 211

22. Price $5.50

FORM NTIS-35 (REV. 3-72)

USCOMM-DC 14952-P72

EPA-R2-73-084a
(API Publication 4180)

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Contract No. 68-02-0251
Program Element No. 1A2015

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Prepared for

AMERICAN PETROLEUM INSTITUTE
1801 K STREET, NW
WASHINGTON, D.C. 20006

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OFFICE OF RESEARCH AND MONITORING
U.S. ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

June 1973

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This report has been reviewed by the Environmental Protection Agency and approved for publication. Approval does not signify that the contents necessarily reflect the views and policies of the Agency, nor does mention of trade names or commercial products constitute endorsement or recommendation for use.

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*These appendices appear in the Data Supplement Volume which is available as a separate report.

ABSTRACT

Information on air-pollutant emissions from residential and commercial heating equipment was developed in a 2-year field investigation conducted by the Battelle Columbus Laboratories. Emissions measured were CO, HC, NO_x, SO_2, particulate, and smoke. The program, jointly sponsored by the American Petroleum Institute and the U.S. Environmental Protection Agency, covered emissions from 33 residential heating units and 13 commercial boilers – including effects of various combustion parameters and fuel-oil compositions.

Residential Units

Although performance similarities among units were noted during runs with varied air adjustments, each unit had unique emission characteristics. For the representative cross section of residential units investigated, it was found that the largest reduction in emissions could be achieved by replacing poorly performing units, as identified from smoke measurements made during service inspections. Tuning of the units that were generally performing well reduced smoke levels but produced only slight reductions in emissions on a gravimetric basis. Tuning to lower smoke by increasing the air adjustment alone could result in sharply rising emissions of CO and HC for some units, unless established tuning practice is followed using field-type instruments for smoke and CO_2 measurements.

Burners equipped with flame-retention-type combustion heads produced lower emissions than those with conventional heads, and newer burners performed with lower emissions than did older burners.

Commercial Boilers

For the sample of typical commercial boilers, which ranged from 40 to 600 boiler horsepower in capacity, emissions were measured for 33 different combinations of boilers and fuels at various loads and excess air settings. Although some performance differences were noted, operating parameters within the normal range of adjustment had minor effect on gaseous emissions.

Fuels included in the investigation were natural gas and five grades of fuel oil, including a 1-percent-sulfur residual oil that was transported to each boiler site for use as a reference fuel. Fuel characteristics had a significant effect on emissions, especially particulate and NO_x. Particulate emissions with the 1-percent-sulfur oil averaged about 30 percent of those for conventional No. 6 oil; particulate emissions for No. 2 oil averaged only about 3 percent of that for No. 6 oil. NO_x emissions were lowest with gas and the lighter grades of fuel oil and increased with increasing fuel nitrogen content.

Emission Factors

On the basis of this investigation, new emission factors are suggested for use in emission inventories and in evaluating control strategies. Separate emission factors are suggested for residential oil-fired units and for gas-fired and oil-fired commercial boilers, with a distinction between fuel-oil grades or types.

ACKNOWLEDGMENT

The authors wish to acknowledge the assistance and helpful comments of the EPA Project Officer, Robert E. Hall, and the API SS-5 Task Force during the course of this program. Membership on the SS-5 Task Force was as follows:

E. Landau (Chairman)	Asiatic Petroleum Corporation
R. C. Amero	Gulf Research & Development Company
S. P. Cauley	Mobil Oil Corporation
H. E. Leikkanen	Texaco Inc.
B. L. Mickel	American Oil Company
R. E. Paterson	Chevron Research Company
C. W. Siegmund	Esso Research & Engineering Company
R. A. Beals	National Oil Fuel Institute, Inc.
J. R. Gould	American Petroleum Institute.

The assistance of the Commercial-Industrial Air Pollution Committee of the American Boiler Manufacturers Association is acknowledged for their cooperation in the selection of commercial units and assistance in defining appropriate test conditions. The authors also wish to acknowledge the enthusiastic cooperation of those manufacturers who made available their commercial boilers and plant facilities and who donated the services of skilled service technicians to assist in the burner adjustments needed to achieve the desired matrix of test conditions.

Acknowledgment is made for the cooperation of the homeowners who granted permission for the field team to set up its battery of instruments and for their patience under the inconvenience of having normal comfort control of their heating system interrupted during the two or three days of measurements.

Special acknowledgment is due W. H. Axtman, Assistant Manager of the American Boiler Manufacturers Association, and Margaret Mantho, Statistical Editor of *Fueloil & Oil Heat*, for their assistance in preparing the equipment population questionnaires, soliciting replies, and consolidating the statistical data.

The authors are also indebted to numerous Battelle-Columbus staff members who participated in various aspects of the program. Special adknowledgment is made to Technician J. J. Fancelli and J. H. Faught, who served on the field team making the measurements, and to various supporting staff; to R. D. Fischer, D. R. Hopper, and R. E. Thomas, who advised or assisted in the computer and statistical interpretations of data; to P. R. Webb for particle-size measurements; to the secretaries who assisted in the preparation of this report; and to R. B. Engdahl, L. J. Hillenbrand, J. A. Gieseke, and A. Levy, who advised on various sampling and analytical aspects of the program.

FIELD INVESTIGATION OF EMISSIONS FROM COMBUSTION EQUIPMENT FOR SPACE HEATING

to

AMERICAN PETROLEUM INSTITUTE
Project SS-5 Task Force

and

ENVIRONMENTAL PROTECTION AGENCY
Control Systems Laboratory

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SUMMARY

Information on air-pollutant emissions from combustion equipment is essential to environmental quality considerations – including development of emissions inventories, control strategies, and equipment design criteria. Under sponsorship of the American Petroleum Institute and the U.S. Environmental Protection Agency, the Battelle Columbus Laboratories has conducted a 2-year investigation to develop more comprehensive and up-to-date information on emissions from representative residential and commercial fuel-burning equipment for space heating.

The American Petroleum Institute sponsored Phase I of the investigation during the 1970-71 heating season, in which field measurements of gaseous and particulate emissions were made on 20 oil-fired and 2 gas-fired residential units, plus 7 commercial boilers. Those findings were reported in API Publication 4099[1].

The Phase II investigation was conducted during the 1971-72 heating season under the joint sponsorship of the American Petroleum Institute and the Environmental Protection Agency. In the Phase II investigation, more detailed emissions measurements were made over a wider range of conditions on 13 residential units and 6 commercial boilers. This report describes procedures and results for the Phase II investigation and conclusions based on both the Phase I and Phase II studies.

This Executive Summary provides an overview of the findings and conclusions from both Phases I and II.

---

[1] "A Field Investigation of Emissions from Fuel Oil Combustion for Space Heating", by A. Levy, S. E. Miller, R. E. Barrett, E. J. Schulz, R. H. Melvin, W. H. Axtman, and D. W. Locklin. API Publication 4099 (November 1, 1971), available from the API Publications Section, 1801 K Street, N.W., Washington, D. C. 20006.

OBJECTIVES AND SCOPE OF PHASE II

Objectives

The objectives of the Phase II investigation were to develop additional information on air-pollutant emissions from combustion equipment used for residential and commercial heating, including the effects of combustion parameters and fuel composition on emission levels.

Scope

Measurements made on the 13 residential units covered a range of excess-air adjustments for both as-found and tuned operating conditions. For the six commercial boilers, combustion parameters included a range of loads and excess air levels; natural gas and three different grades of fuel oil were fired in five of the commercial boilers to determine effects of fuel characteristics on emissions.

Emission Measurements. The following gaseous pollutants were measured by continuous monitoring equipment sampling from the stack:

- Carbon monoxide, CO
- Total hydrocarbons, HC
- Sulfur dioxide, SO_2 (only for commercial boilers)
- Nitrogen oxides, NO_x ($NO + NO_2$).

In addition, oxygen and carbon dioxide concentrations were measured to define the operating conditions in terms of excess-air levels.

Particulate measurements were made on a gravimetric basis using the EPA sampling train, with a slight modification of procedures specified in EPA Method 5[2]. The particulate emission so determined is termed "filterable particulate" in this Summary and report; the additional contribution of "condensable particulate" is discussed in the report and in Appendix F.

Smoke density measurements were made by the Bacharach hand-pump smoke meter, the standard method used in the oil-burner industry. The smoke spots were evaluated photometrically by a reflectance meter.

Figure I-1 shows the field instrumentation as set up for measurements on a commercial boiler. Details of measurement procedures for both gaseous and particulate emissions are described in Appendixes E and F of this report.

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[2] "Standards of Performance for New Stationary Sources", *Federal Register*, Vol. 36, No. 139, Part II, pp 24876-24895, December 23, 1971.

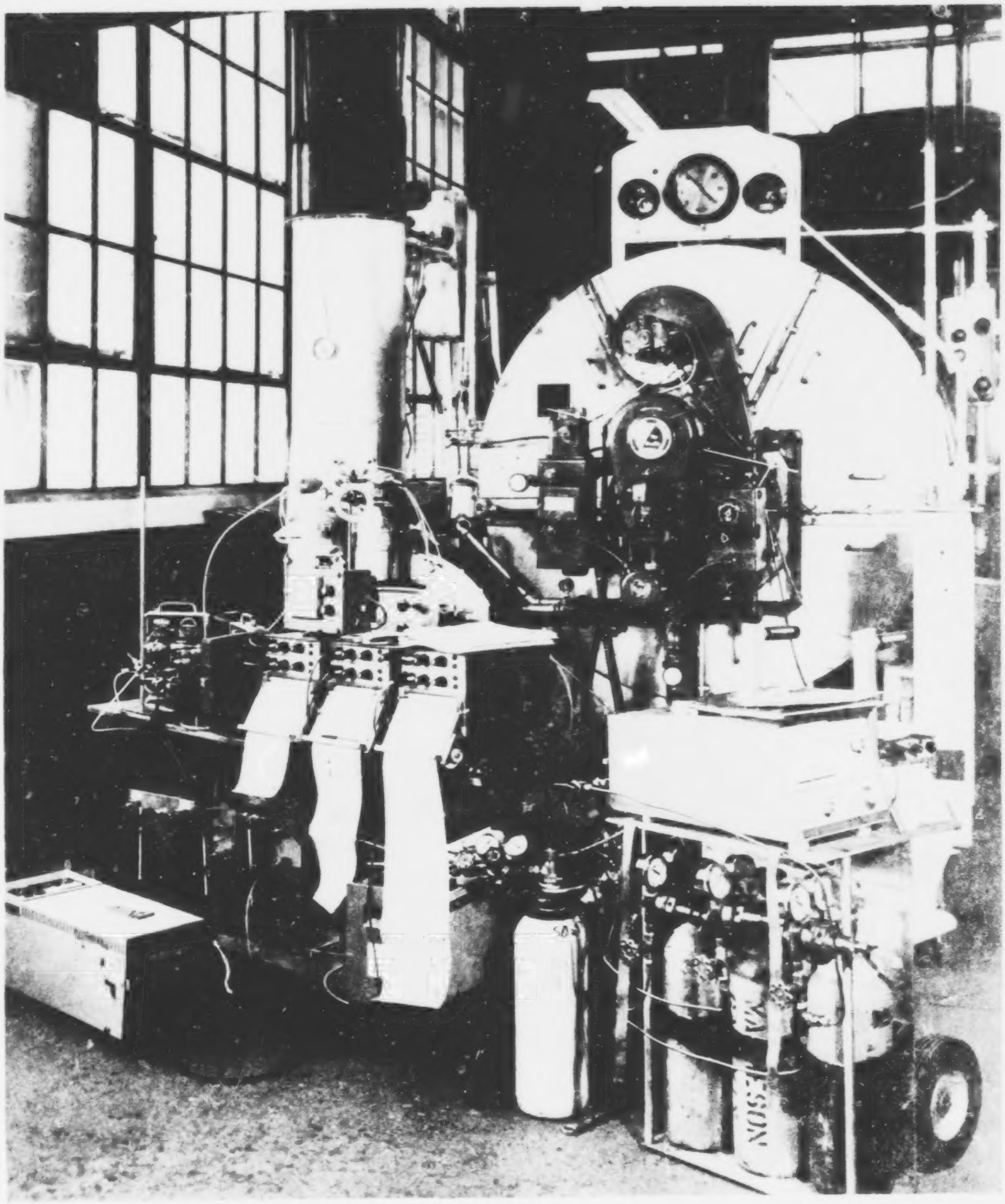

Figure I-1. Field Instrumentation Used for Measuring Emissions From Commercial Boilers

RESIDENTIAL UNITS

A variety of residential oil-fired heating units were selected for the investigation so that the sample would be representative of the field population of equipment currently in service for heating single-family homes in the United States. Criteria for this selection of units were: type of oil burner by atomizing method, burner capacity, type of combustion head for air-fuel mixing, burner age, and type of heating system or unit.

Mix of Units

Table I-1 shows the mix of residential units for the total sample of oil-fired units investigated in Phases I and II.

Table I-1. Mix of Residential Oil-Fired Units in Sample

		Number of Units
By Burner Type	High-pressure	29
	Low-pressure	1
	Other	1
By Burner Capacity	1.0 gph or less	6
	1.01-1.35 gph	15
	1.36-2.00 gph	3
	Above 2.00 gph	7
By Burner Combustion-Head Type (high-pressure burners only)	Conventional head	18
	Flame-retention head	9
	Shell head	2
By Burner Age	5 years or less	17
	6-10 years	1
	11-15 years	7
	Older than 15 years	6
By System Type	Warm-air furnace	12
	Hot-water or steam boiler	18
	Service water heater	1

Conditions Investigated

Measurements of gaseous and particulate emissions, obtained with the heating equipment operating on the homeowner's fuel supply, were made in the *as-found* condition of adjustment and the *tuned condition.*

Tuning. Normal service and adjustment practices were followed in tuning, short of major replacement or renovation. Most units were tuned to a smoke level below No. 2 on the Bacharach scale; the mean smoke was reduced from No. 3.2 for the as-found condition to No. 1.3 for the tuned condition.* Smoke was reduced for over half the units; for most of the others, a slight sacrifice in smoke level permitted an increase in CO_2 for higher overall thermal efficiency. As-found, the mean CO_2 level was 7.9 percent; this was increased to 8.1 percent on tuning.

Types of Runs. Two ypes of runs were made with the residential units in Phase II.

1. **Varied-air runs** (Phase II only) – Gaseous emissions and smoke were determined during steady-state operation for a range of excess-air settings and plotted against CO_2 to determine sensitivity of emissions to air adjustment.**
2. **Cyclic runs** (Phases I and II) – Gaseous and particulate emissions and smoke were measured during repeated cycles of 10 minutes on and 20 minutes off.

Varied-Air Runs

Emission characteristics measured during the varied-air runs were generally similar for most of the residential units. Figure I-2 illustrates the smoke-vs-CO_2 characteristics for steady-state firing of a typical unit, as determined in the varied-air runs for the as-found and tuned conditions. A distinct improvement in performance is noted on tuning, because lower smoke levels could be achieved at the same CO_2 (or excess air setting).

Figure I-3 shows the gaseous emissions for this typical unit in the tuned condition, leaving a low-emission operating range between about 7 and 9 percent CO_2 (corresponding to a range of excess air from about 65 to 110 percent). Although each unit yielded unique characteristic curves, these curves are typical of burners where a relatively wide range of excess-air levels could be achieved. For this unit and several others, CO and HC emissions increased sharply at low CO_2 levels, while smoke levels remained low. This demonstrates that CO and HC emissions can be high if units are adjusted by smoke criteria alone. (NO_x was not highly sensitive to air settings.)

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*These mean smoke values do not include units in need of replacement, as explained subsequently.

**This procedure was similar to ASTM-D2157-65, "Standard Method of Test for Effect of Air Supply on Smoke Density in Burning Distillate Fuel".

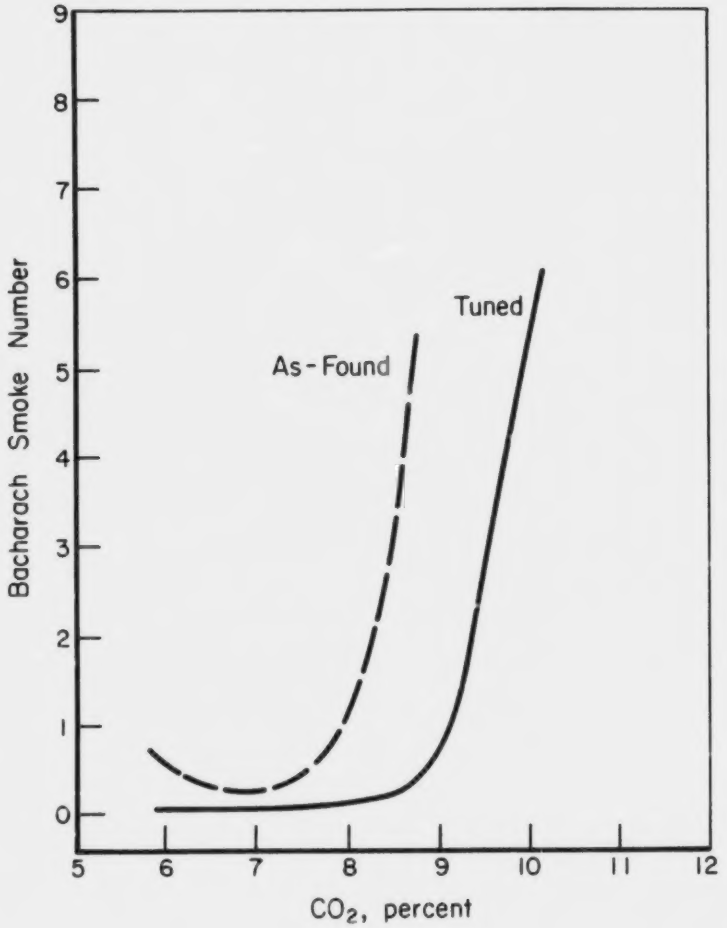

Figure I-2. Typical Smoke Versus CO_2 Curves for a Residential Unit in the As-Found and Tuned Conditions

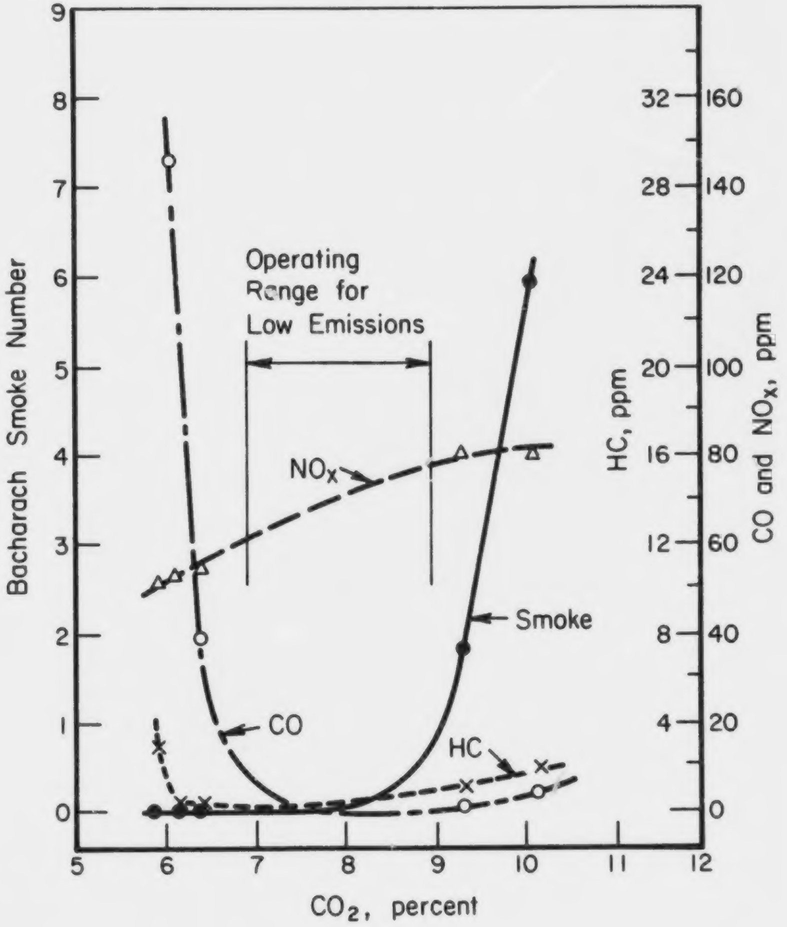

Figure I-3. Typical Smoke and Gaseous Emission Characteristics for a Residential Unit in the Tuned Condition

Cyclic Runs

Figures I-4 and I-5 show the distribution of emission factors and smoke levels measured on both the Phase I and II residential units for cyclic runs in the as-found and tuned conditions. It should be noted that 3 units were in poor condition and in obvious need of replacement; these units yielded oily smoke spots and generally produced emissions of CO, HC, and particulate that were much higher than those for the remaining units.* The oily smoke spots would reveal these units as needing burner replacement; this condition would be detected by an experienced serviceman using field-type instruments.

Effect of Tuning on Emissions. While tuning generally resulted in lower smoke levels, it produced variable effects from unit to unit on gaseous and particulate emissions in the cyclic runs, causing some pollutant emissions to increase and others to decrease.

In terms of the mean emission factors, this investigation showed that the major reduction in CO, HC, and particulate is achieved by identifying and eliminating units in poor condition (those in need of replacement or major repair). For the remaining units, tuning further reduces mean smoke and CO emissions but has little effect on the mean values of other pollutants.

Table I-2 summarizes the reduction in mean pollutant emissions that could be accomplished by the following steps**:

1. Identifying and replacing the units obviously in poor condition.
2. Completing Step 1 and, in addition, tuning the remaining units.

Table I-2. Effect on Mean Emissions of Identifying and "Replacing" Residential Units in "Poor" Condition and Tuning

	Reduction in Emissions, percent	
	Step 1	Step 2
Pollutant	Identifying and Replacing of Poor Units	"Replacement" Plus Tuning
Smoke	–	59
CO	>65	>81
HC	87	90
NO_x	No Change	No Change
Filterable Particulate	17	24

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*For normally performing units (those not showing oil on smoke spots), CO and HC levels were very low. In fact, the family automobile that meets the 1975 EPA emissions standards (as of June 1973) and is driven an average of 12,000 miles would emit annually 25 times as much CO and HC as would be emitted by firing 1000 gallons of oil, a typical annual consumption for a residential unit.

**Values are based on distribution of "poor" units found in the Phase I and II studies – that is, 3 poor units in a total sample of 34 units.

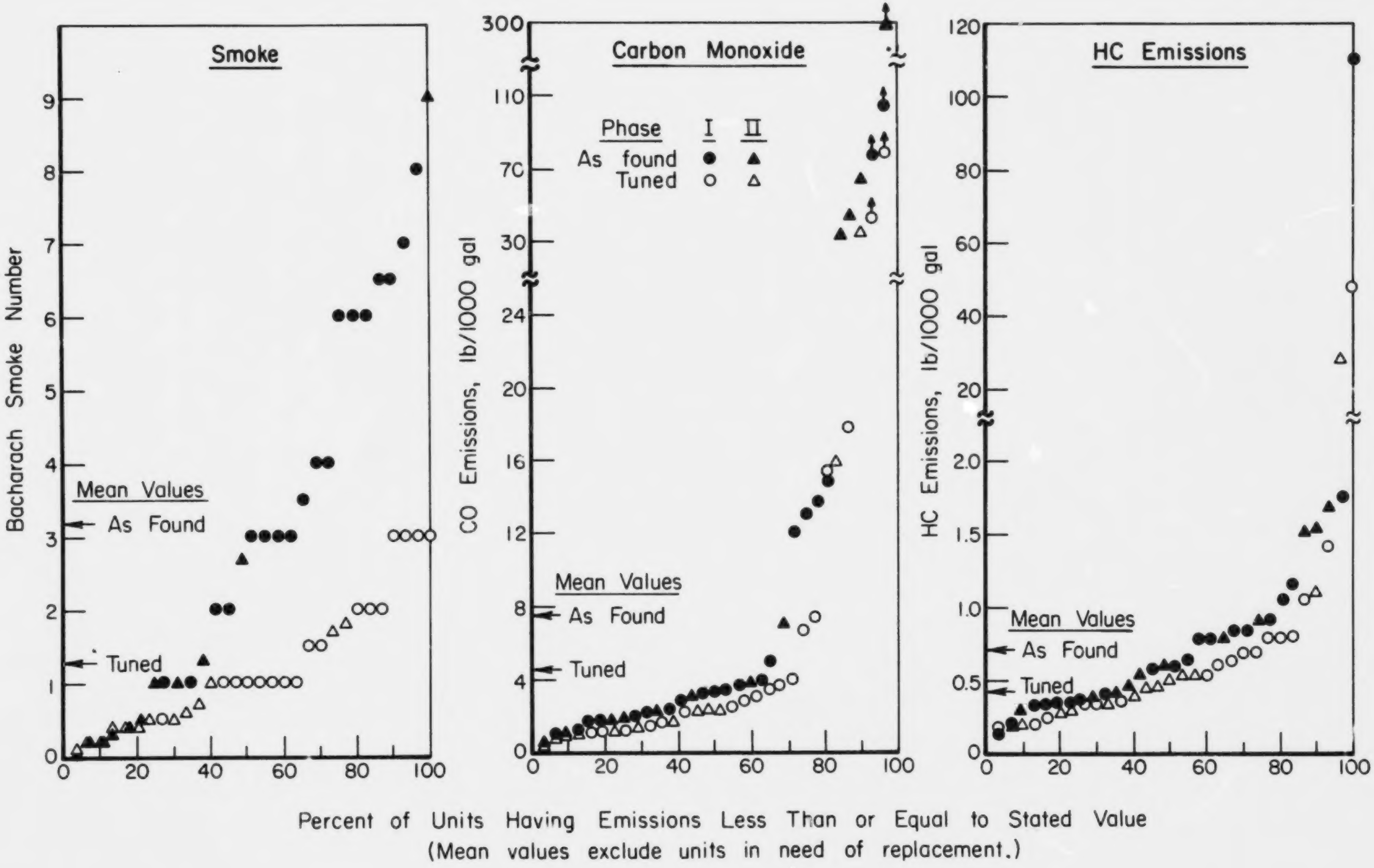

Figure I-4. Distribution of Smoke, CO, and HC Emission for Residential Units

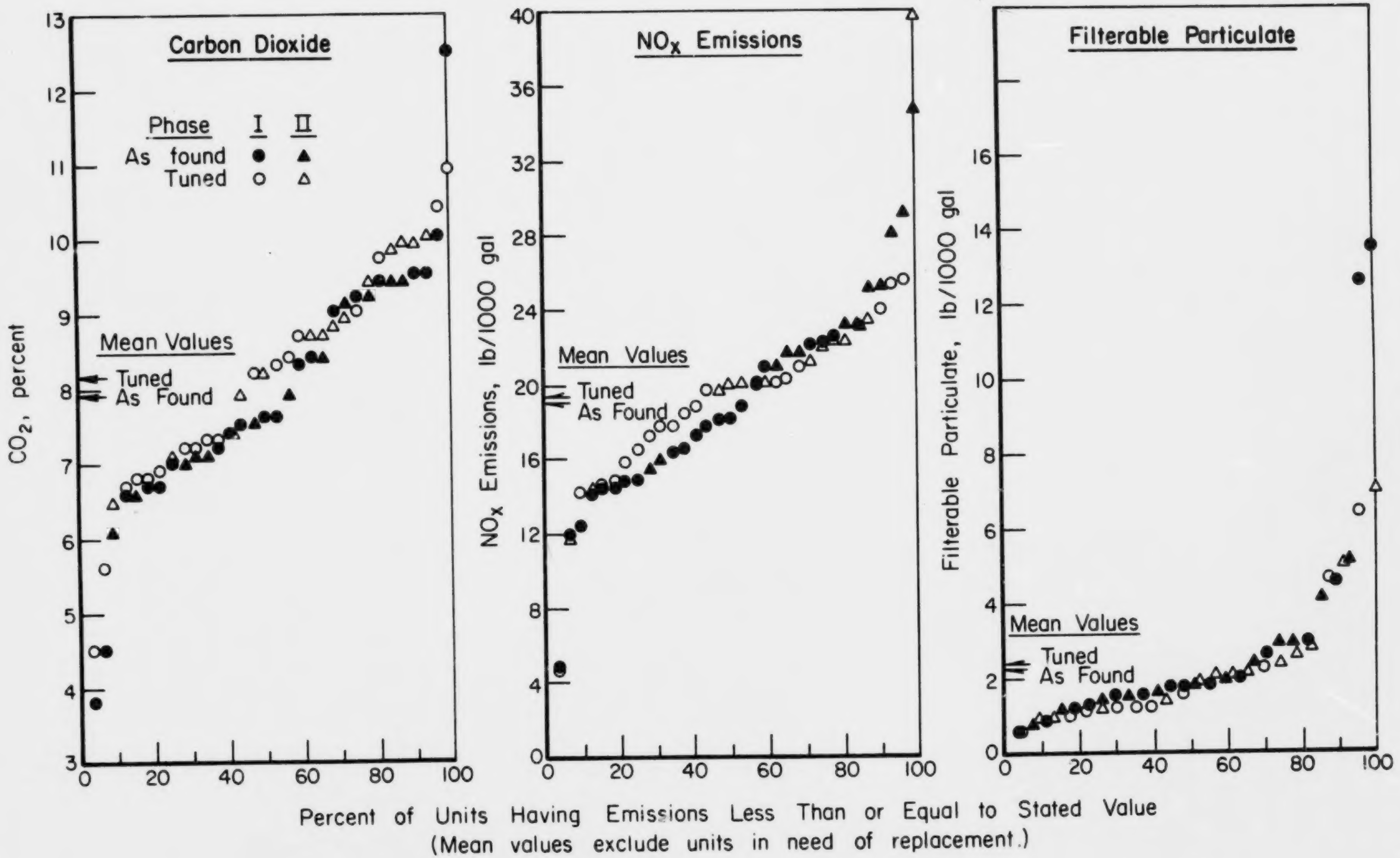

Figure I-5. Distribution of CO_2, NO_x, and Filterable Particulate Emissions for Residential Units

Follow-Up Measurements. For four of the residential units, follow-up measurements were made twice during the heating season at 2-month intervals to investigate the effect of operating time since tuning. Except for one unit which experienced nozzle clogging, only minor shifts in smoke, NO_x, and particulates were noted during the 4-month operating period. Emissions of CO and HC for one unit increased significantly but not to serious levels.

Summary of Residential Emissions and Comparison With EPA Emission Factors

Table I-3 provides a summary of mean emissions for each of the pollutants measured for the residential units during cyclic runs. Mean values of emission factors* for the Phase I and II investigations are shown. Also shown for comparison are the emission factors published by EPA[3].

Table I-3. Comparison of Mean Emissions for Cyclic Runs on Residential Oil-Fired Units

Units	Condition	Units in Sample[a]	Mean Smoke No.[b]	Mean Emission Factors, lb/1000 gal			
				CO	HC	NO_x	Filterable Particulate
Mean Values From Phase I and II Battelle/API/EPA Investigation:							
All units	As-Found	32	(c)	>22.1	5.7	19.4	2.9
	Tuned	33	(c)	>16.4	3.0	19.5	2.3
All units, except those in need of replacement	As-Found	29	3.2	7.8	0.72	19.6	2.4
	Tuned	30	1.3	4.3	0.57	19.5	2.2
Current EPA-Published Emission Factors:[3]							
			–	5.0	3.0	12.0	10.0
Suggested Emission Factors: For residential units in areas having regular service and inspection							
			–	10.0	1.5	20.0	2.5

[a] One unit was a furnace installed in the laboratory and was not included in deriving the mean emissions values for the as-found condition.
[b] Smoke data at 5-minute point of on-cycle.
[c] Oily smoke spots prevented valid mean values.

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*Emission factors represent average emission levels for a category of equipment and are used in area emission inventories and in evaluating control strategies. Emission factors should not be confused with emission standards.

[3] "Compilation of Air Pollutant Emission Factors", U. S. Environmental Protection Agency, Office of Air Programs Publ. No. AP-42 (February 1972).

Suggested Emission Factors for Residential Units

This investigation was conducted over two heating seasons and comprised measurements on 33 oil-fired residential units selected to be generally representative of the existing equipment population. Because this study has provided more extensive data than available at the time the present EPA compilation of emission factors was prepared, it is suggested that the emission factors applying to oil-fired residential equipment be updated as shown in Table I-3.

CONCLUSIONS FOR RESIDENTIAL INVESTIGATION

The principal conclusions reached from this investigation on a representative sample of oil-fired residential heating units are outlined below, considering findings from both Phases I and II.

1. **Inspection and Tuning.** Air pollutant emissions from oil-fired residential heating units can be significantly reduced on an area-wide basis by the use of available service procedures.

   The most effective step in reducing area-wide emissions is the identification and replacement (or major renovation) of units in poor condition. Such units, identified by the presence of oil on smoke measurement spots during this investigation, were found to be contributing a disproportionately large share of the CO, HC, and particulate emissions.

   Tuning the remaining burners by use of good service practices achieved a significant further reduction in smoke and CO emissions. Mean smoke levels were reduced in tuning from 3.2 to 1.3 Bacharach smoke number and mean CO values were reduced from 7.8 to 4.3 lb/1000 gal. Tuning produced little change in NO_x, while filterable particulate and HC emissions decreased slightly.

   Tuning increased the overall thermal efficiency for 60 percent of the Phase II units: the average incremental increase of overall efficiency for all units was 1.7 percent. This has the effect of decreasing total annual emissions due to resulting savings in fuel input.

2. **Range of Emissions and Their Distribution.** A broad range of emission levels was observed for the entire sample of units in the cyclic runs, but the distribution of emission levels was relatively uniform except for those units in need of replacement. NO_x levels showed the least variability.

3. **Emission Characteristics of Individual Burners.** Varied-air runs in Phase II revealed that each burner had its own unique emission characteristics over a range of air settings. Similarities in pattern were noted, but the permissible operating ranges for low emissions and the adjustment sensitivity were widely different among burners. For some burners, an attempt to set a minimum

smoke level by increasing the excess air would result in sharply increasing CO and HC emissions. Hence, both smoke and CO_2 measurements should be used in adjusting a burner to insure low smoke at a high CO_2 level.

4. **Smoke Measurements as Indicator for CO and HC.** The varied-air runs showed that low smoke readings were a good indicator of low CO and HC emissions when operating at the low-excess-air side of the adjustment range; however, smoke was not a good indicator of these emissions at the high-excess-air side of the range.

5. **CO and HC Levels.** Emissions of CO and HC from all units (except those identified as requiring replacement or major repair) were so low during cyclic runs as to be insignificant in terms of contribution to air pollution.

6. **Effect of Combustion Head and System Type.** Burners with flame-retention combustion heads operated with lower mean values of CO, HC, and filterable particulates than did burners with conventional combustion heads. No significant trends were observed relative to other factors of burner or system type.

7. **Effect of Burner Age.** Burner age had a significant influence on emissions, with newer burners yielding lower emissions. Newer burners produced significantly less CO and filterable particulate for the tuned condition and slightly lower levels of HC, NO_x, and smoke for all conditions. The greatest difference between emission levels for new and old burners occurred between the burner age groups divided at 15 years. (These observations as to the effect of burner age are believed to be due to improved burner designs to meet higher performance goals recognized voluntarily by equipment manufacturers in recent years, rather than to a deterioration in service that cannot be restored by competent tuning.)

8. **Effect of Operation Since Tuning.** Follow-up measurements, made twice during the heating season at 2-month intervals for four units, were not consistent. Emissions remained nearly constant for two units. CO and HC emission increased for another unit, while other emissions remained constant. Smoke, CO, and HC increased for the fourth unit, which had malfunctioned due to improper tank filling.

9. **Smoke vs Particulate.** Bacharach smoke readings taken at different points in the firing cycle typically showed that smoke density was greatest during the first minute and reduced as the cycle proceeded. A continuous-tape smoke indicator confirmed that higher levels of smoke frequently occurred on starting and shutdown for brief periods.

   Smoke readings taken at relatively steady-state conditions during the cyclic runs were not a good measure of filterable particulate emissions which included sampling during starting and shutdown transients. Smoke measurements may be more indicative of emissions of fine particulates, which are the principal concern in health effects and atmospheric visibility. Additional laboratory investigations are planned to examine the relationship between smoke and particulate for steady-state and cyclic conditions over a range of excess-air settings.

10. **Suggested Emission Factors.** Emission factors for use in emission inventories and implementation plans were suggested on the basis of this investigation and are shown in Table 1-3. Suggested emission factors are higher than EPA-published factors for CO and NO_x, but are substantially lower for HC and filterable particulates.

COMMERCIAL BOILERS

The 13 commercial boilers sampled in Phases I and II were selected to be generally representative of the commercial boiler population in terms of boiler type, capacity, and burner type. Boiler sites were selected with the aid of a committee of the American Boiler Manufacturers Association (ABMA) to ensure that boiler load and burner adjustment conditions could be controlled. For Phase II, another selection criterion was the feasibility of firing as many as four different fuels in a given boiler; these fuels included natural gas, No. 2 heating oil, conventional grades of residual oil, and a low-sulfur residual oil (1 percent sulfur) that was used as a reference fuel and transported from site to site in a tank truck. A total of 33 boiler/fuel combinations were sampled.

Mix of Boilers

Table I-4 summarizes the mix of commercial boilers covered in this investigation for both Phases I and II.

Table I-4. Mix of Commercial Boilers in Sample

		Number of Boilers
By Boiler Type	Scotch firetube	8
	Firebox firetube	2
	Cast iron	2
	Watertube	1
By Boiler Capacity (Boiler Horsepower)[a]	10-100 BHP	5
	101-300 BHP	6
	301-600 BHP	2
By Oil-Burner Type[b]	Air atomizing	8
	Pressure atomizing	4
	Rotary atomizing	1

[a] Boiler capacity rating; one boiler horsepower is equivalent to approximately 33,500 Btu/hr output.

[b] Seven of these boilers had dual-fuel burners capable of firing natural gas.

Statistics developed in a special survey conducted for this program in cooperation with ABMA confirmed that the Phase II sample was reasonably representative of the current field population of commercial boilers. Detailed data from the survey are presented in Appendix B.

Conditions and Fuels Investigated

All measurements on the commercial boilers were made at steady-state conditions. Gaseous emissions and smoke were measured in Phase II while the boiler was operated at four different loads and at about five excess-air levels at each load. Nominal loads were full, 80 percent, 50 to 60 percent, and low-fire setting, which was generally from 30 to 40 percent. Because of the long sampling time required at each setting, particulate emissions were measured at only about five selected points for each boiler. (Phase I measurements generally consisted of gaseous emissions and smoke measurements at four loads and particulate emission measurements at two points.)

Base-Line Condition

To provide a common basis for comparing emission levels from various boilers, a "base-line condition" was defined after consultation with ABMA to identify a condition typical of boiler operation most frequently encountered in the field. This base-line condition was defined nominally as 80 percent load with an air setting to achieve flue-gas compositions of 12 percent CO_2 for oil firing and approximately 10 percent CO_2 for gas firing. This corresponds to the following excess-air levels: approximately 28 percent for No. 6 oil, 25 percent for No. 2 oil or light residual oil, and 15 percent for natural gas.

Measurements of gaseous and particulate emissions and smoke were made for this base-line condition on all boilers in Phases I and II.

Fuels

Table I-5 identifies the fuels fired in each of the boilers for both Phases I and II. The fuels normally used as "house fuels" are identified. LSR refers to the low-sulfur residual oil used as a reference fuel in Phase II; a similar fuel was fired in one boiler during Phase I.

Typical Emission Trends

Each of the commercial boilers generally exhibited the expected pattern of emission characteristics, with smoke sharply increasing as low excess-air settings were approached from the normal operating range. Figures I-6 and I-7 illustrate typical curves of smoke and NO_x emissions vs excess air for one boiler fired at 80 percent load with three fuel oils and natural gas. Both smoke density and NO_x levels were strongly influenced by fuel grade. Effects of load on smoke and NO_x were relatively minor. Emissions of CO and HC were consistently low for the commercial boilers in normal operating ranges.

Table I-5. Summary of Fuel Types Fired in Various Commercial Boilers Boilers for both Phases I and II Listed in order of capacity.

Boiler Horsepower and Type	Burner Atomizing Type	Phase	Fuels Fired[a]					
			No. 2	No. 4	No. 5	No. 6	LSR[b]	Gas
40-hp Cast iron	Pressure	II	▲	–	–	–	–	●
60-hp Scotch	Pressure	I	▲	–	–	–	–	●
80-hp Scotch	Air	I	–	–	▲	–	–	–
80-hp Firebox	Pressure	II	●	–	▲	–	■	●
90-hp Cast iron	Air	II	●	▲	–	–	■	●
100-hp Scotch	Air	II	●	–	–	▲	■	●
125-hp Scotch	Rotary	I	–	–	–	▲	–	–
125-hp Firebox	Pressure	I	▲	–	–	–	–	–
150-hp Scotch	Air	I	–	–	▲	●	■[c]	–
200-hp Scotch	Air	I	–	▲	–	–	–	–
300-hp Scotch	Air	II	●	–	–	▲	■	●
350-hp Scotch	Air	I	–	▲	–	–	–	–
600-hp Watertube	Air	II	●	–	–	▲	■	●

[a] Legend: ▲ House fuel oil normally used.
● Alternate house fuel.
■ Low-sulfur residual oil (Phase II reference oil).

[b] Low-sulfur residual oil commercially available on East Coast (1.0 percent sulfur content).

[c] A low-sulfur residual oil (0.5 percent sulfur) was fired in this unit in addition to the 1.0 percent sulfur oil.

Effects of Fuel

Significant effects of fuel properties were observed in the investigation, especially as related to particulate and NO_x emissions.

Particulate Emissions. Particulate emissions and smoke increased with increasing fuel-grade designations when several fuel oils were fired in the commercial boilers at a given excess-air setting; these emissions were consistently low when firing natural gas.

The effect of fuel grade on filterable particulate emissions is summarized in Figure I-8 for all boilers from Phases I and II firing oil at base-line conditions. Particulate is plotted against API gravity as an indicator of burning characteristics and fuel grade – the heaviest fuels having lowest API gravity. Approximate ranges of API gravity for different fuel grades are shown.

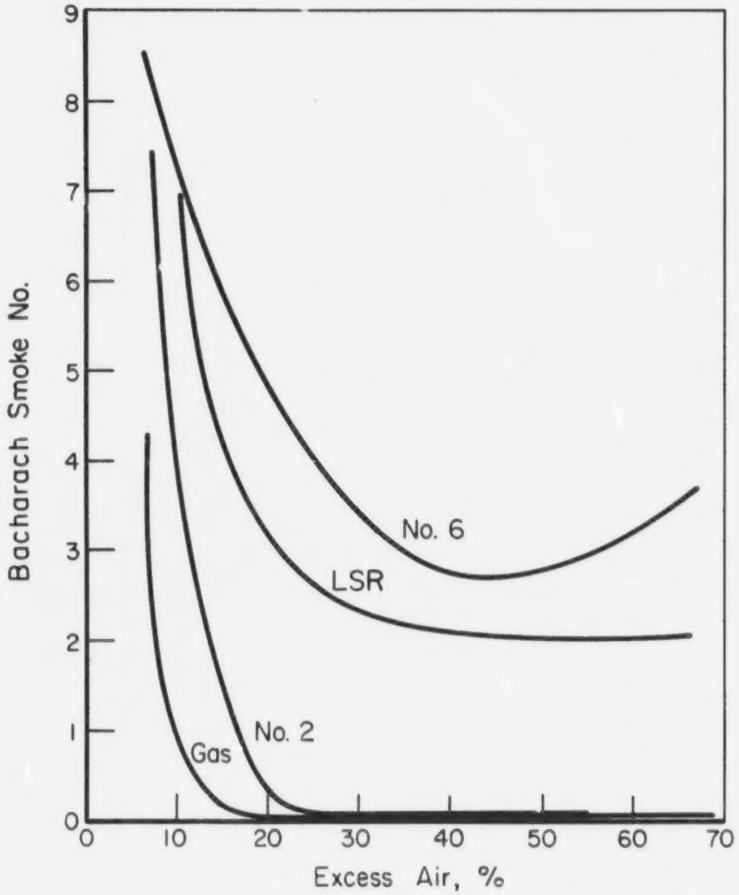

Figure I-6. Typical Characteristics of Smoke Versus Air for a Commercial Boiler Firing Different Fuels at 80-Percent Load

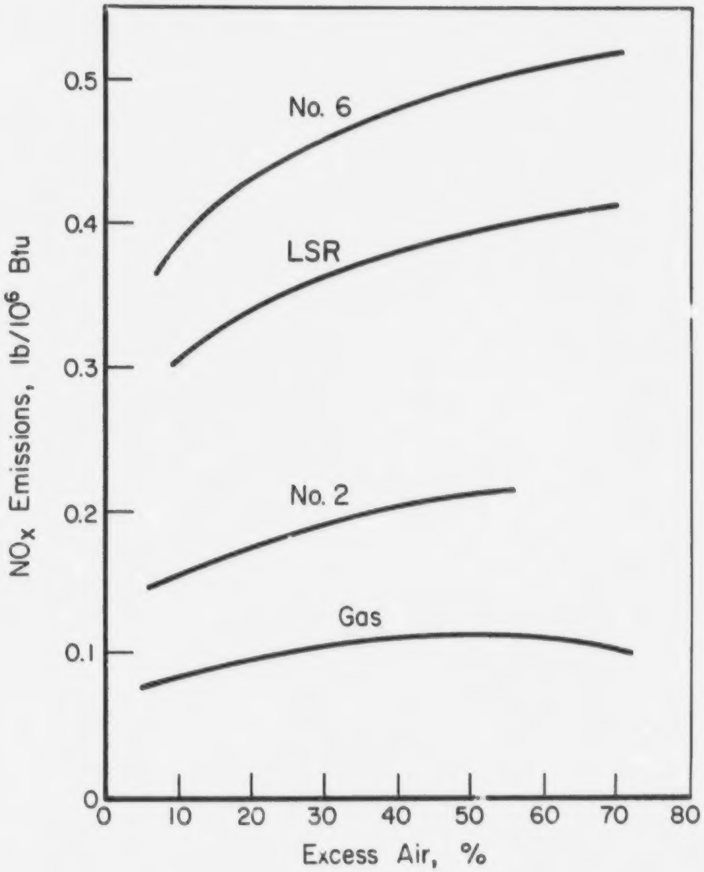

Figure I-7. Typical NO$_x$ Emissions Versus Excess Air for a Commercial Boiler Firing Different Fuels at 80-Percent Load

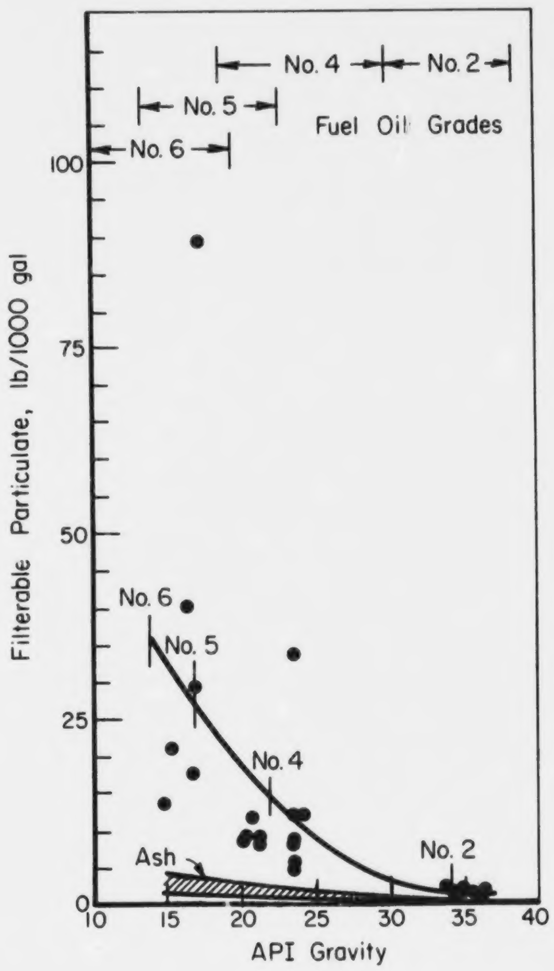

Figure I-8. Relation of Filterable Particulate and API Gravity for the Commercial Boilers Firing Different Fuels at Base-Line Conditions – Phases I and II

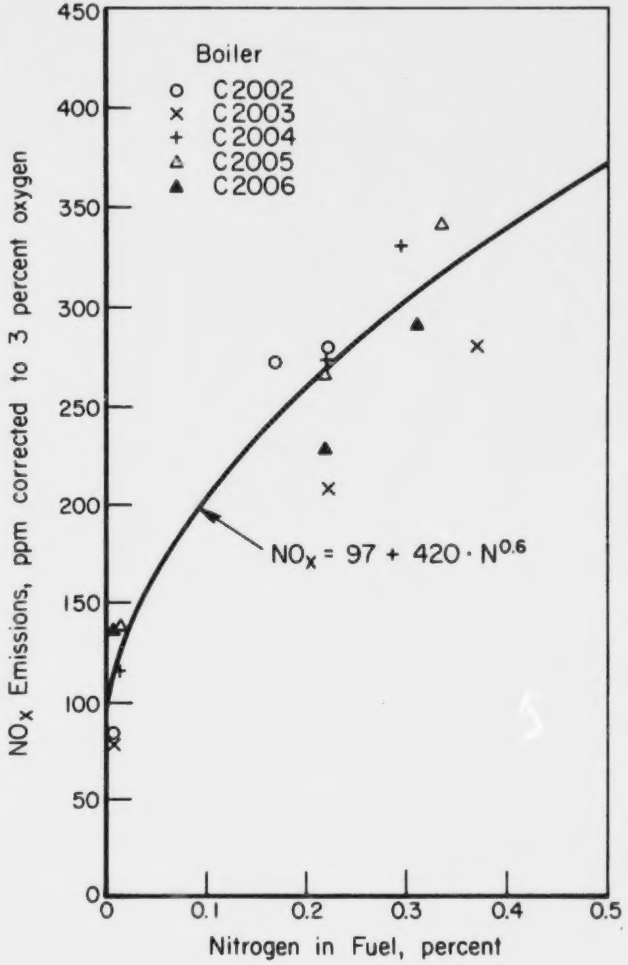

Figure I-9. Relation of NO_x Emissions and Fuel Nitrogen for the Commercial Boiler Firing Different Fuels at Base-Line Conditions – Phase II

Ash content tends to be higher for fuels of low API gravity but is not sufficient to account for higher particulate levels with heavier fuels. The band of ash content for the fuels in this investigation is shown in Figure I-8.

The 1-percent sulfur residual oil used as a reference fuel was closer in performance to a No. 4 or No. 5 oil; it yielded filterable particulate levels about equal to those from No. 4 oil and only one-third of those from the No. 6 oil.

Effect of Fuel Nitrogen on NO_x

Figure I-9 shows the strong effect of fuel nitrogen on NO_x emissions from the commercial boilers in which several fuel oils were fired at base-line conditions. The zero-nitrogen intercept is indicative of NO_x formed by thermal fixation, which is dependent upon flame temperature and other combustion parameters influenced by boiler/burner design. The slope of the curve of NO_x versus fuel nitrogen reflects the conversion of fuel nitrogen to NO_x.

Both the thermal component of NO_x and the conversion of fuel nitrogen to NO_x vary from boiler to boiler. The equation that best fits the data from boilers in which fuels of different nitrogen content were fired is NO_x (ppm at 3% O_2) = $97 + 420 \cdot N^{0.6}$. This indicates that about 62 percent of the fuel-bound nitrogen was converted to NO_x for a 0.2 percent nitrogen fuel, 47 percent for a 0.4 percent nitrogen fuel, and 38 percent for a 0.7 percent nitrogen fuel. Other investigators have reported conversion of fuel nitrogen to NO_x in the same range.

It should be pointed out that other fuel properties, such as gravity and viscosity, also varied from fuel to fuel in this program; thus, the NO_x levels shown in Figure I-9 may include effects of factors other than fuel nitrogen.

Summary of Oil-Fired Commercial Boiler Emissions

Emissions for the commercial boilers firing oil at the base-line conditions are summarized in Table I-6. Mean emission values are shown separately for each grade of fuel; the mean fuel properties shown for each grade of fuel pertain to the fuels fired in this field investigation. (Since broad ranges in properties exist within each grade, these values cannot be considered to be representative of all fuels within these grade designations.)

Suggested Emission Factors for Oil-Fired Commercial Boilers

This investigation has included emission measurements on 13 commercial boilers with 26 boiler/fuel-oil combinations and with a variety of operating conditions. The emission levels measured in this investigation show sufficient effects of fuel properties to justify the conclusion that emission factors intended for use in compiling emission inventories or in evaluating control strategies should discriminate between fuel-oil grades where these are known.

Accordingly, Table I-7 presents suggested emission factors by fuel grade.

Table I-6. Summary of Emissions from Commercial Boilers

Mean emissions by fuel-oil grade measured in Phases I and II at base-line conditions[a] for 13 boilers ranging in capacity from 40 - 600 boiler hp.

Fuel Oil Grade	Number of Boilers	API Gravity, mean	Sulfur %, mean	Viscosity SSU @ 100 F, mean	Smoke No., mean	Mean Emission Factors, lb/1000 gal				
						CO	HC	NO_x	SO_2[c]	Filterable Particulate
No. 2	8	35	0.2	34	0.9	0.5	0.15	18	132·S	1.5
No. 4	3	22	1.7	120	2.6	0.8	0.15	73	149·S	7.1
No. 5	3	19	1.8	220	3.0	1.9	0.22	54	175·S	13.
No. 6	5	16	1.9	3600	3.9	1.1	0.30	78	173·S	38.
LSR[b]	6	23	1.0	400	2.9	0.3	0.27	49	157·S	13.

[a] Base-line operating conditions: 80 percent load and air adjustment for 12 percent CO_2 flue-gas concentration.

[b] Low-sulfur residual oil, typical of 1.0 percent sulfur residual oil being marketed on the East Coast in 1971 - 1972.

[c] S = multiplication factor equal to percent sulfur content of fuel.

These values were derived from the findings of this investigation in such a way as to normalize the effects of fuel properties for the different grades of fuel that were "encountered" in the field during the investigation but may have been atypical of that grade on a national basis. The procedure used to establish the suggested values in Table I-7 was to plot CO, HC, and particulate emission factors for each boiler/fuel combination at base-line conditions vs API gravity as an indicator of fuel characteristics. (Although not a universal index of emission performance, API gravity has the practical effect of reflecting some of the other important factors and is one of the most commonly available fuel properties.)

"Best curves" were fitted by a least-squares technique; Figure I-8 shows the curve for particulates. Emission factors were then obtained from the curves by assuming API gravity values typical of the various grades of fuel as follows:

	Fuel Grade	Typical API Gravity, degrees @ 60 F
Distillate Oil	No. 2	34
Conventional Residual Grades	No. 4	22
	No. 5	17
	No. 6	14
Low-Sulfur Residual (1.0% S)	LSR	23

Table I-7. Suggested Emission Factors for Oil-Fired Commercial Boilers and Comparison With EPA-Published Factors

Fuel Oil Grade[a]	Emission Factors, lb/1000 gal[b]				
	CO	HC	NO_x[c]	SO_2[d]	Filterable Particulate
Suggested Emission Factors: Based on Battelle/API/EPA Investigation[e]					
No. 2	0.5	0.17	$20 + 78 \cdot N^{0.6}$	$142 \cdot S$	1.2
No. 4	0.9	0.24	$20 + 85 \cdot N^{0.6}$	$154 \cdot S$	14.0
No. 5	1.1	0.28	$20 + 87 \cdot N^{0.6}$	$159 \cdot S$	27.0
No. 6	1.2	0.30	$20 + 89 \cdot N^{0.6}$	$162 \cdot S$	36.0
LSR[f]	0.9	0.23	$20 + 84 \cdot N^{0.6}$	$153 \cdot S$	12.0
Current EPA-Published Emission Factors[3]					
Distillate	0.2	3.0	40 to 80	$142 \cdot S$	15.0
Residual	0.2	3.0	40 to 80	$157 \cdot S$	23.0

[a] These values are based on mean emission data for the identified fuel grades having typical API gravity as follows: 34 degrees API for No. 2; 22 for No. 4; 17 for No. 5; 14 for No. 6; and 23 for LSR. Where actual API gravity is known, interpolated values should be used.

[b] To convert to emission factors in lb/10^6 Btu, multiply these values by 0.0069. (The actual multiplier varies slightly with fuel grade, being about 0.0071 for No. 2 fuel oil and 0.0066 for No. 6 fuel oil.)

[c] N = multiplication factor equal to percent nitrogen in fuel oil. If concentration is unknown, the following values are suggested: 0.01 percent for No. 2; 0.2 percent for No. 4; 0.3 percent for No. 5; 0.4 percent for No. 6; and 0.2 percent for LSR.

[d] S = multiplication factor equal to sulfur content in fuel.

[e] Assuming steady-state base-line operating conditions: 80 percent load and air adjustment for 12 percent CO_2 flue-gas concentration.

[f] LSR: low-sulfur residual oil (1.0 percent S).

These typical values were estimated considering values suggested by API representatives and average values from the field fuels. The resulting emission factors are shown in Table I-7 as "suggested emission factors".

Suggested NO_x emission factors are based on fuel nitrogen content and reflect decreasing conversion of the fuel nitrogen to NO_x as fuel nitrogen levels increase. Emission factors recommended for SO_2 are proportional to sulfur content of the fuel.

For comparison, Table I-7 also shows the current EPA-published emission factors, which distinguish between only two categories of fuel oil: distillate and residual oil.

Summary of Gas-Fired Boiler Emissions and Suggested Emission Factors

Table I-8 summarizes emissions as measured from seven commercial boilers firing natural gas and gives suggested emission factors. The major changes suggested are to reduce emission factors for HC and filterable particulates.

Table I-8. Suggested Emission Factors for Gas-Fired Commercial Boilers With Comparison of EPA-Published Factors

	Emission Factors, lb/10^6 cu ft[a]				
	CO	HC	NO_x	SO_2	Filterable Particulate
Mean Emission From 7 Boilers: Battelle/API/EPA Investigation[b]	16.7	3.7	105	Nil	5.7
Suggested Emission Factors[3]	20.0	4.0	100	0.6	6.0
Current EPA-Published Emission Factors[3]	20.0	8.0	100	0.6	19.0

[a] To convert to emission factors in lb/10^6 Btu, multiply these values by 0.00098.

[b] Base-line Operating Conditions: 80 percent load and air adjustment for approximately 10 percent CO_2 flue-gas concentration.

CONCLUSIONS FOR COMMERCIAL BOILER INVESTIGATION

Major conclusions from the findings of this investigation of emissions from a representative sample of commercial boilers are outlined below, based on the combined results of Phases I and II.

1. **Emission Characteristics of Commercial Boilers.** The varied-air runs with the commercial boilers showed that the smoke curve generally was flat over a range of excess-air levels but increased sharply as the combustion air was reduced below normal air settings. For oil firing, smoke levels tended to increase before CO and HC increased. With gas firing, CO and HC increased before the smoke density increased.

   To adjust the air setting to acceptable smoke (or minimum smoke for that boiler/fuel combination) would require combustion air settings as high as 30 to 40 percent excess air for most of the boilers operating with the heavier fuels. It was possible to fire gas at 10 percent excess air without exceeding No. 1 smoke; however, 20 percent excess air was required to avoid rapidly increasing CO emissions with gas. Smoke increased slightly at high excess air in only a few cases with oil firing and in one case with gas firing.

   These observations suggest that field-type instruments for measuring smoke and CO_2 can be used satisfactorily in adjustments for oil firing to minimize CO and HC as well as smoke; however, a CO indicator is needed in air adjustments for gas firing. (CO and HC levels at base-line conditions were generally low for all boilers firing either oil or gas.)

   NO_x was relatively insensitive to air setting.

2. **Effect of Load.** Load generally had little influence on emission levels, including NO_x. Smoke and particulate increased with load on several boilers when firing No. 6 oil, suggesting that limitations in mixing or combustion volume were being reached at high load. (For minimum smoke at low fire, some boilers require a higher excess-air setting at this point, and this adjustment is frequently made in the field when setting the control linkage.)

3. **Effect of Boiler and/or Burner Design on Emission Levels.** Considerable variation in emissions was noted from boiler to boiler, even when firing the same fuel at base-line conditions. Particulate emissions with the reference fuel varied by a factor of 4.4 from lowest to highest. Smoke varied only by a factor of 1.4. Emission levels of CO and HC were judged to be sufficiently low to be insignificant for all oil firing.

   NO_x emissions for various boilers varied from lowest to highest by a factor of 1.3 at base-line conditions when firing the reference fuel. Boiler and/or burner design variables did not show a consistent influence on NO_x emissions, even when firing low-nitrogen fuels.

No attempt was made in this investigation to optimize emission performance by modification of the burner design or atomizer; thus, the data are not adequate to indicate what minimum emission levels might be achieved by optimizing burner design for a given boiler/fuel combination.

4. **Effect of Fuel Oil Properties on Smoke and Particulate.** Fuel oil grade had an important bearing on smoke and particulate levels. For the boilers operating at base-line conditions, the heavier fuels (i.e., lower API gravity) yielded higher smoke and particulate, although the heavier grades were fired at conditions used in normal practice.

   A regression analysis indicated that the single most important fuel property influencing filterable particulate at base-line conditions was carbon residue (correlation coefficient of 0.68). API gravity also had a significant effect (correlation coefficient of 0.55). Viscosity at firing temperature was relatively insignificant (correlation coefficient of 0.25).

   An index combining carbon residue, viscosity at firing temperature, carbon content, and API gravity yielded a good correlation with filterable particulate (correlation coefficient of 0.86).

   The low-sulfur residual oil having 1-percent sulfur was closer to a No. 4 or 5 grade in viscosity, gravity, and other burning characteristics than to conventional No. 6 oil. Particulate emissions with this fuel averaged one-third those of the conventional No. 6 oil.

   NO_x levels tended to be higher with the heavier fuels, but this is traceable to generally higher fuel-bound nitrogen with the heavier grades.

5. **Effect of Fuel Nitrogen on NO_x.** NO_x emissions increased nearly linearly with increasing fuel nitrogen content when different fuel oils were fired in the same boiler. The slope of NO_x versus fuel nitrogen curves indicated conversion of about 40 to 60 percent of the fuel nitrogen to NO_x.

   A combination of other factors influenced thermal components of nitrogen fixation, but a consistent pattern was not detected; firing rate did not have as consistent an influence in Phase II as observed in Phase I.

6. **Gas Firing vs Distillate Oil.** Smoke and particulate emission levels with gas firing were generally lower than with No. 2 oil when firing the same boiler at base-line conditions. On a Btu-input basis, mean particulate emissions at base-line conditions for gas firing were one-third of those for No. 2 oil.

   Mean NO_x levels with gas firing were three-fourths of those for No. 2 oil. For half the boilers, gas firing yielded slightly higher NO_x levels than did No. 2 oil at base-line conditions.

   CO and HC emissions were higher for gas than No. 2 oil: CO over five times higher, and HC about three times higher.

7. **Correlation of Smoke vs Particulate.** For the commercial boilers operating at steady-state conditions, Bacharach smoke numbers showed consistent trends in relationship to filterable particulate when firing different fuels in the same boiler. This suggests that families of correlation curves may be possible, with each curve characteristic of a given boiler firing a given fuel. If this relation could be further defined for a series of similar boiler designs, predictions of particulate performance could be made using simpler field measurement techniques.

8. **Suggested Emission Factors.** Because of the large differences in emission levels in commercial boilers due to the effects of fuel properties, separate emission factors should be used for different grades of fuel oil in emission inventories or implementation plans. Suggested emission factors were established by fuel grades using the trends identified in this investigation; these are shown in Table I-7. Suggested emission factors for boilers firing natural gas are shown in Table I-8.

   Other than to account for the fuel-oil grade discrimination, the major suggested changes of EPA-published values are reductions in emission factors for HC and particulate from firing No. 2 oil. In addition, it is suggested that emission factors for NO_x be based partly on fuel nitrogen content. Suggested changes for natural gas firing are reductions in emission factors for HC and particulate.

EMISSIONS FROM RESIDENTIAL UNITS

This chapter describes the Phase II investigation of emissions from residential oil-fired heating units. The principal effort of Phase II was devoted to more detailed field measurements of emissions covering more conditions than was possible for the Phase I study. The discussion is presented as follows:

- Units Included in the Phase II Investigation
- Procedures Used in the Field Investigation
- Emission Results for Cyclic Runs
- Emission Results for Varied Air Runs
- Correlation of Smoke and Particulate.

Where applicable, results of Phase I emission measurements have been included in the analyses of the influence of various factors on emissions.

UNITS INCLUDED IN THE PHASE II INVESTIGATION

The scope of equipment in the Phase II investigation included 13 oil-fired residential heating units with firing rates from 0.6 to 1.75 gph.

Basis for Selection of Equipment

Selection of residential oil-burning equipment installations to be studied in Phase II of this program was directed toward making the total sample of the Phase I and II units reasonably representative of the population of equipment in service, considering such factors as

- Burner type
  - atomizer type and combustion head
- Capacity or firing rate
- Installation type
  - matched unit (burner-boiler unit or burner-furnace unit) or conversion burner
- Heating system type
  - hot water, steam, or warm air
- Age of installation.

Obviously, within the limits of a program of this size, it was not possible to include a large number of units in each category. However, an attempt was made to include a distribution of oil-fired units similar to the distribution of units now in service.

As an initial step in the selection of the residential units to be included in the Phase II investigation, a questionnaire on the existing oil-burner population was submitted to a number of burner service organizations. Replies to the questionnaires were slow in being returned, hence, the Phase II investigation was launched using previously published oil-burner population data for selection of residential units. Sources of information on oil-fired equipment that were consulted included *Fueloil & Oil Heat* magazine and the National Oil Fuel Institute. This information, combined with the experience background of the project team, was used in establishing a suitable mix of units. The Battelle-Columbus recommendations as to the general equipment mix were then examined and approved by the EPA Project Officer and the API SS-5 Task Force.

Results of the questionnaire confirmed that the equipment mix selected was representative of the existing equipment population.

Selection of Equipment Mix and Individual Units

Table II-1 outlines the types of equipment included in the residential equipment mix and shows the number of units of each type included in this investigation for Phase II and the total for the two phases. The selected mix of units is compared with the distribution of the U.S. equipment population.

Background data obtained from the questionnaires on residential equipment mix are shown in Appendix A. These data represent the best statistical data available covering detailed categories of equipment now in service on a national basis. High-pressure gun-type burners are clearly the dominant burner type for residential heating. Also, burners of 1.35 gph or less account for nearly 70 percent of the residential heating units.

Individual residential field units were selected by the Battelle field team with the assistance of Consultant W. H. Axtman and with the aid of a qualified oil-burner servicing organization. The majority of the units investigated were selected from the service contract files of the organization, and the initial contact with the homeowner was made by the servicing organization. The servicing organization supplied a skilled serviceman to tune or adjust the burners following the initial measurements.

Description of Residential Units

Table II-2 shows the number designations for the residential units which are used to identify emission data elsewhere in this report for the specific residential units. This table also includes a brief identification of burner type, firing rate, heating system type, and burner and system age – including whether the installation is (1) a "matched" factory-designed burner-furnace or burner-boiler unit or (2) a "conversion" installation where the burner has been added in the field to a basic furnace or boiler, possibly originally designed for coal firing. (Nearly all furnaces and boilers being installed today are matched units.)

Twelve of the units (Units 23 through 34) were field units in use for residential heating. An additional unit, identified as Unit 35, was a new residential oil-fired furnace which was set up in the laboratory at Battelle-Columbus during the Phase I study for the calibration and checkout of instruments, sampling procedures, and the operating-cycle timing. All thirteen of the units were high-pressure gun type; five had flame-retention combustion heads and one had a Shell combustion head.

Table II-1. Mix of 31 Residential Units in Sample Compared With Distribution of U.S. Equipment Population in Service

	Units in Sample			
	Number of Units		Percent of Total[a]	Distribution of U.S. Equipment Population, percent[b]
	Phase II	Total[a]		
By Burner Type				
High-Pressure Gun	13	29	94	84
Low Pressure	0	1	3	10
Vertical Rotary Wall-Flame	0	1	3	5
Vaporizing	0	0	0	1
By Burner Capacity, 9 gph				
<1.0	4	6	20	34
1.01-1.35	7	15	49	35
1.36-1.65	1	2	6	14
1.66-2.00	1	1	3	8
2.01-3.0	0	5	16	5
>3.0	0	2	6	4
By Burner Combustion-Head Type (High-Pressure only)				
Conventional Head	7	18	62	81
Flame-Retention Head	5	9	31	11
Shell Head	1	2	7	8
By Burner Age, years				
<5	9	17	55	19
6-10	0	1	3	23
11-15	1	7	22	28
16-20	3	3	10	19
>20	0	3	10	11
By System Type				
Furnace	9	12	39	52
Boiler	4	18	58	48
Water Heater	0	1	3	–

[a] Including units from both Phases I and II.

[b] From References 4 and 5 as follows:
4 Fueloil and Oil Heat, "The Typical Oil Burner", Vol. 31, No. 6 (June 1972), pp 44-45.
5 Fueloil and Oil Heat, Special Study, Vol. 30, No. 1 (January 1971), pp 22, 24.
These statistics are summarized in more detail in Appendix A.

Table II-2. Description of Residential Units for Phase II

All units had high-pressure gun burners.

Unit	Burner Head Type	Firing Rate[a], gph	Heating-System Type[b]	Combustion Chamber Material	Estimated Age, yr Burner	Estimated Age, yr System
23	Flame retention[c]	1.35	CI boiler, conversion, water	Firebrick	<1	21
24[d]	Conventional	1.00	Steel forced-air furnace unit	Metal	4	4
25	Flame retention[c]	1.35	Steel boiler unit, water	Ceramic felt	<1	<1
26[e]	Shell	1.75	CI boiler, conversion, steam	Firebrick	2	9
27	Flame retention	1.35	Steel boiler unit, steam	Hard refractory	5	5
28	Flame retention	1.00	Steel forced-air furnace unit	Metal	2	8
29	Conventional	0.75	Steel forced-air furnace unit	Hard refractory	18	18
30	Conventional	0.60	Steel forced-air furnace unit	Hard refractory	18	18
31	Conventional	1.50	Steel forced-air furnace unit	Firebrick	20	20
32	Conventional	1.00	Steel forced-air furnace unit	Metal	<5	<5
33	Flame retention	0.85	Steel forced-air furnace unit	Firebrick	3	15
34	Conventional	0.75	Steel forced-air furnace unit	Hard refractory	11	11
35	Conventional	1.00	Steel forced-air furnace unit	Ceramic felt	2	2

[a] Nominal firing rate or nozzle capacity as found, gph.

[b] "Unit" describes "matched" burner-furnace or burner-boiler units engineered by the manufacturer. CI denotes cast-iron construction.

[c] High-speed fan motor (3450-rpm).

[d] Unit 12 from Phase I study.

[e] Unit 16 from Phase I study.

Nine of the Phase II oil-fired units were warm-air furnaces and four were water or steam boilers. Only two of the thirteen units investigated this year were conversion units. The ages of the burners and heating systems ranged from less than 1 to about 20 years.

PROCEDURES USED IN THE RESIDENTIAL FIELD INVESTIGATION

Measurements on residential heating units were started in December, 1971, and, except for the last follow-up runs, were completed in February, 1972. The investigation of each residential unit required from 2 to 3 days, including instrument setup and measurements under the test conditions. The measurements were made by a three-man field team supported by other Battelle-Columbus staff and a consultant.

Burner Conditions Investigated

Emissions from residential units were monitored during cyclic operation (repeated cycles of 10 minutes on and 20 minutes off) and during steady-state operation while the excess air was varied. Both cyclic and varied-air runs were made at three sets of burner conditions:

A "As found condition" of burner adjustment using house fuel

T "Tuned condition" using house fuel

R "Reference fuel" run under the same conditions as the tuned run to provide a base line for comparison of units.

The letter designations (A, T, and R) are used elsewhere in this report to key the condition of the runs.*

Definition of Tuned Condition. Experience on the first few of the Phase I units had shown variability among servicemen in their criteria for properly adjusted units. For the remaining Phase I and II units, the tuned condition was defined as the best adjustment (in terms of the smoke-CO_2 relationship) that could be achieved by a skilled serviceman with normal cleanup, nozzle replacement, simple sealing, and adjustment procedures with the benefit of field instruments. It did not include major repairs, modernization, or replacement of major parts that would require special charges to the homeowner (e.g., replacement of a combustion chamber). Further details of the adjustment procedure are presented in Appendix D.

Influence of Tuning on Smoke and CO_2. Figure II-1 shows the influence of tuning on smoke and CO_2 levels for the Phase II units, with unit numbers identified. (Unit 35, the laboratory unit at Battelle, is not included in discussions of tuning, as it had no normal as-found condition, but is treated as a tuned unit in data tabulations.) Due to the generally low smoke levels in the as-found condition, tuning reduced smoke in only 6 of the 12 units. In 9 of the 12 units the CO_2 setting was increased.

Figure II-2 shows the distribution of smoke and CO_2 levels for the 12 residential units included in the Phase II investigation together with the 20 oil-fired residential units included in the Phase I investigation. For the Phase II units only, 75 percent operated with a No. 2 smoke or less in the as-found condition and all units operated at No. 2 smoke or less in the tuned condition. The mean smoke level for the 12 Phase II units was 1.5 for the as-found condition and 0.6 for the tuned condition. The smoke levels measured during the Phase II investigation for both the as-found and tuned conditions were significantly below smoke levels measured during the Phase I study.**

The average CO_2 was 7.9 percent for the as-found and 8.5 for the tuned condition for the 12 Phase II units that were tuned. The plot of CO_2 values for the as-found condition for Phase II data were in a narrower range (6.1 to 9.4) than for Phase I data (3.8 to 12.5); 75 percent of the Phase II units had CO_2 levels of 7.9 to 9.9 in the tuned condition.

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*The cold start condition investigated in the Phase I procedure was not included in Phase II because the gaseous emissions measured for these runs during Phase I did not differ appreciably from the emissions obtained after repeated cycles.

**Extensive inquiry of the field team and study of the smoke spots and data have not revealed why the Phase II smoke data were lower than Phase I data.

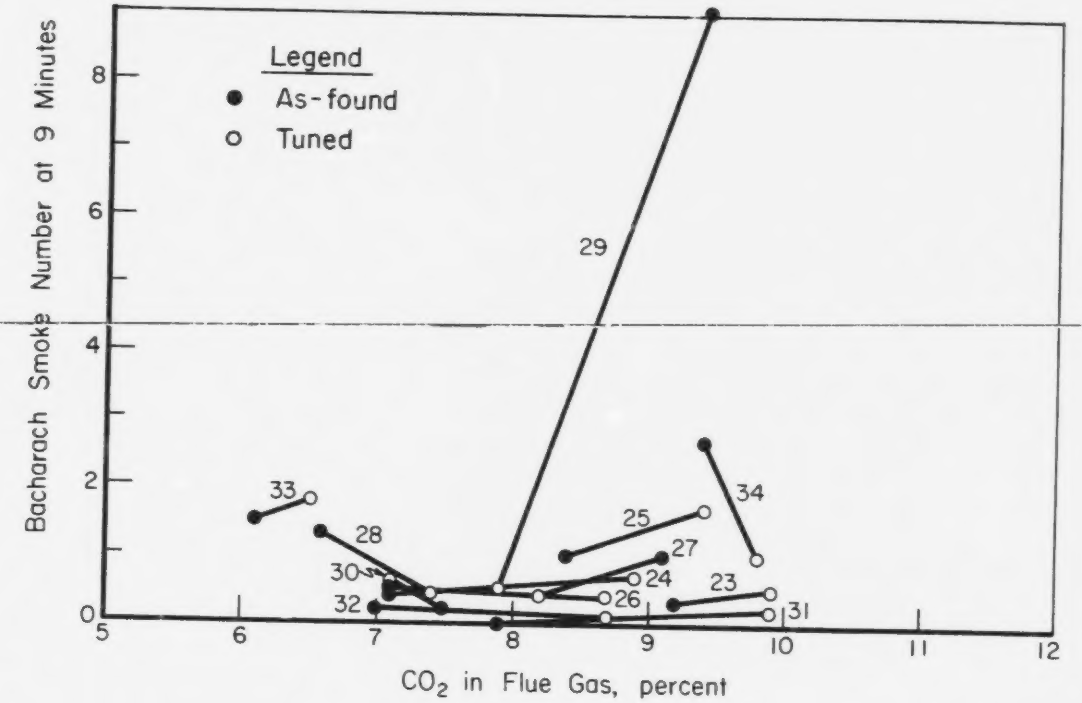

Figure II-1. Operating Conditions for 12 As-Found and Tuned Residential Units

Reference Fuel Condition. To obtain a base line or reference for the variety of burner units, gaseous emissions and smoke were measured for each residential unit during cyclic and varied-air operation while firing a reference fuel in the tuned condition. This reference fuel was selected as a high-quality No. 2 hydrotreated fuel.

Properties of all fuels fired in the residential units are tabulated in Appendix C, Tables C-1 and C-2.

Operating Conditions Investigated

Emission measurements were made while the residential units were fired at two different operating conditions or types of runs, as follows:

1. Cyclic Runs – Measurements were made during repeated cycles of 10 minutes on/2[illegible] minutes off.
2. Varied-Air Runs – Measurements were made during steady-state operation for a range of excess air-settings and plotted against CO$_2$ using procedures similar to ASTM D2157-65[6].

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[6] "Standard Method of Test for Effect of Air Supply on Smoke Density in Burning Distillate Fuel", ASTM D2157-65(70).

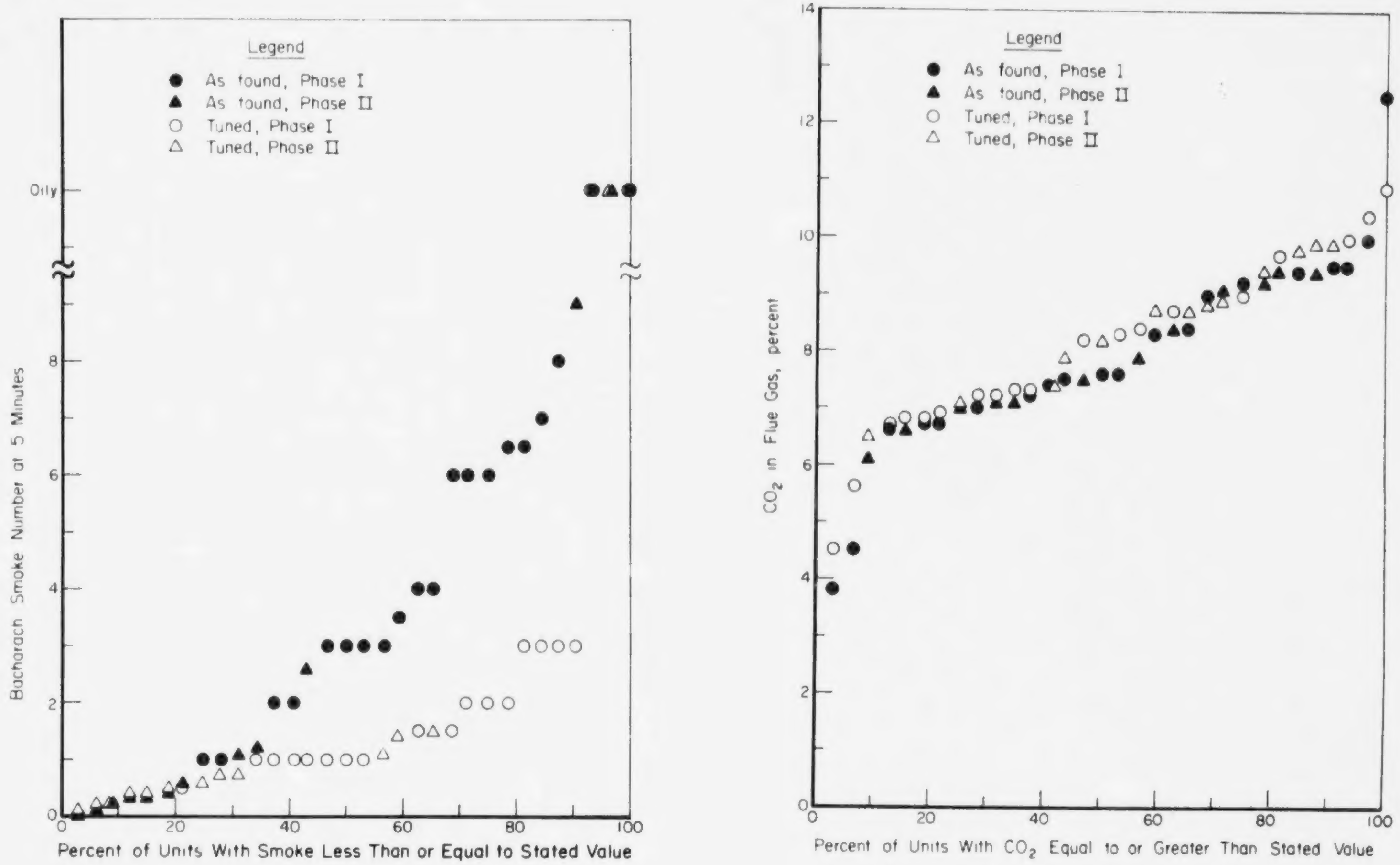

Figure II-2. Distribution of Smoke and CO_2 Levels as Measured in As-Found and Tuned Residential Units for Phases I and II

Measurements of gaseous emissions and smoke were made for both cyclic and varied-air runs for the as-found, A, tuned, T, and reference-fuel, R, conditions. Particulate emission measurements were limited to cyclic runs.

Selection of Operating Cycle. The same operating cycle was used for cyclic runs in residential units during Phase II as was used during Phase I to provide a consistent operating mode for emission measurements. The cycle, 10 minutes on and 20 minutes off, was based on the following criteria:

1. Emission data from different units could be compared on a common basis independent of the effects of outdoor weather on operating modes.
2. The field program would not be seriously delayed or limited by warm weather during the normal heating season. (Normal operation during warm weather produces very infrequent firing.)
3. Multiple cycles of controlled operation would allow the burner and combustion chamber to reach a repeatable thermal condition.
4. The on-period would be much longer than the response time of the monitoring equipment and long enough to allow gaseous emissions to reach equilibrium values.
5. A 10-minute on-time is longer than will be encountered with direct burner control by a modern heat-anticipating room thermostat, where 5 cycles per hour at 50 percent on-time is the design basis but may be shorter than encountered for a hydronic system controlled by the temperature of a water circuit or by steam pressure. A choice of 10 minutes is a reasonable compromise.
6. The 1/3 operating time or "load" of the 10-minutes-on/20-minutes-off cycle represents a reasonable average load condition during the colder part of a heating season.

The 10-minutes-on/20-minutes-off cycle is equivalent to 2 cycles per hour at 33 percent on-time. This cycle is typical of the average recorded for four units observed during a period of 5 months during the 1971-1972 heating season. The operational data for these four units are presented under "Measurements on Follow-Up Units" (page II-36).

A limited investigation was made of the effect of cycle length on emissions. These data are reported under "Experiments on the Effect of Cycle" (page II-40).

Varied-Air Operation. Gaseous emissions and smoke were measured at each of the three burner conditions (A, T, and R), while the excess air level was decreased from the full-open setting to a setting producing about a No. 6 or 7 smoke. These data are intended to provide information about the sensitivity of emissions from the burners as related to excess-air adjustments in each burner condition.

The procedure for the varied-air runs was similar to ASTM D2157-65(70)[6]. Steps were as follows:

1. The burner air gate was set at the full-open position and emissions were measured.
2. The air gate was closed and smoke was monitored until the knuckle of the smoke curve was reached (the point at which smoke increased sharply with small decreases in excess air), then emissions were measured.
3. Emissions were measured at several points between Points 1 and 2 by setting the air gate at intermediate positions.
4. The air gate was closed until a No. 5 to 7 smoke was obtained and emissions were measured.
5. Emissions were measured at one or more points between Points 2 and 4.

Emissions were measured at about six points for each burner condition. Measurements were made after the furnace had been firing for at least 30 minutes and had operated at the test condition for at least 10 minutes or after the gaseous emission readings became constant.

Follow-Up Measurements. Follow-up measurements were made on four residential units. Three sets of measurements were made for these units at the following times:

Initial visit – mid-December
1st follow-up visit – mid-February
2nd follow-up visit – late April.

The complete set of measurements, including gaseous and particulate emissions for the A, T, and R conditions, were made during the initial visit. For the 1st follow-up visit, only gaseous emissions were measured (firing both house and reference fuels). During the 2nd follow-up visit, gaseous emissions were measured for house and reference fuels and particulate emissions were measured for the reference fuel only. All follow-up measurements were made during cyclic operation of the unit.

Emission Measurements – Instruments and Techniques

Prior to measurements in the field, all the equipment and instruments required for the investigation were standardized and checked out in several runs on a residential oil-fired furnace at Battelle-Columbus. Sampling procedures and test sequences were also checked out at this time.

An established set of operational procedures was routinely followed for each unit investigated. Stack gases were sampled and supplied directly to continuous monitoring equipment set up alongside the heating unit.

Gaseous Emissions. Measurements were made of the following gaseous emissions under various conditions of operation using the methods noted as follows (Details of instrumentation and procedures for measuring gaseous emissions are described in Appendix E.):

Emission	Measurement Method
CO_2	NDIR (nondispersive infrared) and Fyrite
O_2	Amperometric and Fyrite
CO	NDIR
Hydrocarbons (total)	Flame ionization
NO_x	Dry electrochemical (used for initial and 1st follow-up visits) NDIR with converter (used for 2nd follow-up visit)
NO	NDIR

Smoke and Other Combustion Parameters. Smoke was measured using the Bacharach hand pump smoke meter and the standard procedures adopted by ASTM[7]. In addition to these measurements, other combustion conditions were measured, including

- Firing rate, measured volumetrically
- Stack temperature, measured in the flue at the particulate sampling location
- Stack draft, measured in the flue at the particulate sampling location.

Particulate Emissions. Particulate emissions were sampled using the EPA sampling rig[2,8]. This train is described in Appendix F. A special feature of this sampling train is the inclusion of two water impingers or bubblers (in an ice bath) downstream from the filter. The impingers were originally intended to collect any condensable material (at 70 F) that would exist as vapor at filter temperature and, thus, pass through the filter and also collect any solid particulate that passes through the filter. Later, EPA abandoned use of the impinger catch in determining particulate emissions for stationary sources[8] as there was indication that reactions occur in the impinger to generate material that is included in the weight measurement of particulate, even though the material does not exist as particulate either in the flue gas or in the atmosphere[9].

To insure that the most meaningful information was obtained from the particulate samples collected on this investigation, the probe wash, the filter catch, and the impinger wash were treated separately and particulate weights were recorded on each. In this report, particulate data are reported as filterable (including the probe and filter catches) and total (combining the filterable and the material found in the water impingers). However, it should be pointed out that even the filterable catch obtained using the EPA sampling train may not be directly comparable to the particulate catch obtained using other sampling trains because of differences in the procedures for washing the probes and differences in sampling rates and volumes.

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[7] "Standard Method of Test for Smoke Density in the Flue Gases from Distillate Fuels", ASTM D2156-65(70).

[8] "Standards of Performance for New Stationary Sources", Federal Register, Vol. 36, No. 139, Part II, pp 15704-15722, August 17, 1971.

[9] "Standards of Performance for New Stationary Sources", Federal Register, Vol. 37, No. 55, Part I, pp 5767, March 21, 1972.

Previous experience at Battelle suggests that acetone washing may not be adequate to remove all particulate from the probe. Therefore, for this investigation two washing procedures were used: (1) the EPA procedure and (2) a modified EPA procedure referred to as the MEPA procedure in this report. First, the probe, filter holder, and impingers were washed using procedures specified by EPA. Then the modified procedure was used wherein additional washings were made to insure complete removal of deposited particulate. The complete procedures and the resulting data are discussed further in Appendix F.

Timing of Measurements for Cyclic Runs. Measurements of gaseous emissions were made continuously over the 10-minute-on period of the cycle. Special tests of the response of the sampling system and instruments to step changes in pollutant concentrations showed a 90 percent response in less than 72 seconds for all gaseous pollutants. All emission factors were based on time-average values over the 10-minute-on period, including peaks at starting but not including peaks at shutdown – when the combustion air flow would be diminished and the measured concentrations would not be meaningful.

Bacharach smoke measurements were made at three points in the firing cycle: at 1, 5, and 9 minutes. The smoke numbers used in this report are generally for the 9-minute point in the cycle, as this is most typical of the smoke that servicemen would normally measure.* However, in the statistical comparisons including Phase I data the 5-minute smoke data are used, as only that data were obtained on all Phase I units.

Particulate sampling was conducted during the 10-minute-on period of the burner for six consecutive cycles beginning with the second cycle. The particulate sampler was started just before burner start-up and continued to just beyond shutdown for each cycle.

Emission Transients During Cyclic Runs. Figure II-3 shows typical profiles of gaseous emission transients during cyclic operation of residential oil burners. Peaks are generally noted for CO and HC at starting and shutdown when there is transient imbalance of the fuel-air mixture or flame temperatures are low. For most units, the HC concentration in the flue gas (after the start-up peak) was less than the ambient HC concentration. For NO_x there is some lag in sampling and NDIR analysis on starting, but the gradual rise in NO_x is more likely due to combustion chamber warm-up.

Smoke at starting and shutdown follows a similar transient effect as does CO and HC. On ignition, an instantaneous over-rich condition can occur which is compounded by the fact that fuel nozzle delivery rate is generally highest; the nozzle is relatively cool on starting. On shutdown, a smoke puff can occur if the fuel pump cut-off is not prompt. Smoke transients at both start-up and shutdown tend to vary widely from unit to unit.

Emission Data Used for Calculating Emission Factors. Emission factors reported for the cyclic runs of Phase II are the dose average for all gaseous pollutants. The dose average values were obtained by dividing the integrated area under the emission curve by the cycle "on"-time.

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*ASTM Standard D2157-65(70), "Standard Method of Test for Effect of Air Supply on Smoke Density in Burning Distillate Fuels", states that the burner should operate for 15 minutes before the smoke measurements are begun.

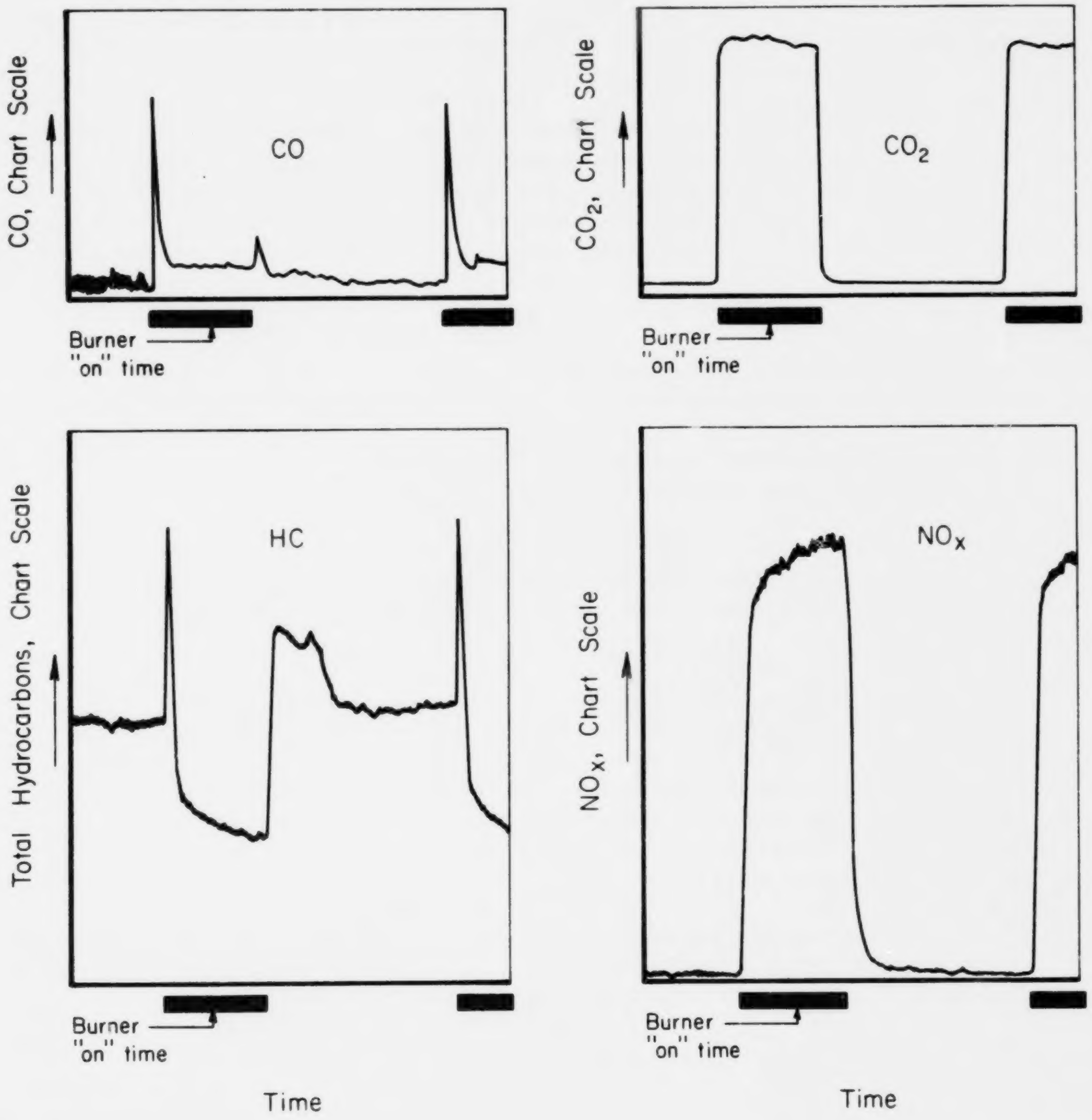

Figure II-3. Typical Gaseous-Emission Profiles of Residential Units During 10-Minutes-On/20-Minutes-Off Cyclic Operation

For the Phase I study[1], 10th-minute readings were used for data summaries and for calculating NO_x emission factors, because the NO_x monitors had slow response. However, the response of the instruments used for Phase II is sufficiently rapid so that dose average readings are considered more representative of the overall cyclic operation. NO_x emission factors for Phase I units summarized in this report were corrected to the dose average value (from 10th-minute data) by multiplying the 10th-minute data by the ratio of dose average data to 10th-minute data obtained on Phase II units (about 0.96).

EMISSION RESULTS FOR CYCLIC RUNS

The following section contains results of emission and smoke measurements during cyclic operation of residential units. Emission data are compared for different burner conditions and burner and installation design features. Results of measurements during cyclic runs on the four follow-up units are summarized to show the effect on emissions of operating time since tuning. In addition, the results of laboratory experiments on the effect of cycle on smoke and gaseous emissions are presented.

Summary of Emission Data and Emission Factors

Table II-3 provides a comprehensive summary of emission measurements for the cyclic runs on the 13 residential units in Phase II.* This table includes operational data defining conditions, measured gaseous emissions in ppm, particulate loading, and calculated emission factors based on fuel input (lb of pollutant per 1000 gallons of fuel).

Effect of Tuning and Fuel

Tuning. Table II-4 summarizes the tuning of the 12 Phase II field units, showing the changes in smoke, CO_2, and efficiency and showing qualitative effects on emissions.

All units were tuned to a smoke level below 2.0, with the average smoke reduced from 1.5 to 0.6. Smoke was reduced for 6 of the 12 units; for another three units, smoke was increased less than 0.5 while increasing CO_2 for higher efficiency; CO_2 was increased for nine units, with the average shifting from 7.9 to 8.5 percent.

Tuning of the residential units generally produced an increase in unit efficiency**. The average incremental increase in unit efficiency was 1.7 percent, with the efficiency increasing for seven units, decreasing for three units, and remaining essentially unchanged for two units. The range of the incremental change in efficiency was from +8.8 percent to -3.9 percent. An incremental increase in efficiency of 1.7 percent would reduce fuel consumption by about 2.4 percent; hence, emissions would be reduced by the same amount.

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*Follow-up measurements for Units 23 through 26 are included separately in Table II-10.

**Although the flue gas temperature was not measured at the breeching, as should be done for efficiency calculations, approximate efficiency calculations were made using the gas temperature at the particulate sampling point.

Table II-3. Summary of Emissions and Emission Factors for Cyclic Runs – Phase II Residential Units

Unit and Condition[a]		CO_2, %	O_2, %	Excess Air, %	Smoke No. at 9 Min	Stack Temperature, °F[b]	Firing Rate, gph	Emission Data at O_2 Level, dose average ppm				Particulate Loading, mg/sm³ [c]		Emission Factors, lb/1000 gal				
								CO	HC	NO	NO_x	Filterable	Total	CO	HC	NO_x as NO_2	Particulate[c] Filterable	Total
23	A	9.2	9.1	68	0.3	470	1.20	3.7	8.3	67	85	10.7	20.5	0.61	0.79	23.1	1.55	2.94
	T	9.9	7.8	54	0.5	480	–	7.7	5.7	82	89	7.2	26.0	1.17	0.50	22.2	0.93	3.44
	R	9.4	8.2	60	0.4	480	1.30	2.6	3.2	75	79	6.4	20.5	0.41	0.29	20.5	0.88	2.82
24	A	7.1	12.0	120	0.4	645	1.04	222.0	12.2	39	78	6.1	15.4	42.28	1.52	27.9	1.17	2.93
	T	8.9	9.0	71	0.7	525	–	4.1	3.1	71	76	19.0	47.6	0.69	0.30	21.1	2.82	7.02
	R	9.2	8.5	64	0.8	520	0.86	9.5	4.5	69	71	18.8	32.2	1.53	0.42	18.8	2.64	4.53
25	A	8.4	9.0	75	1.0	490	1.35	10.6	5.4	42	56	5.7	25.0	1.83	0.53	15.9	0.83	3.73
	T	9.4	7.3	56	1.7	450	–	8.6	5.9	47	47	7.4	19.4	1.32	0.52	11.8	0.97	2.57
	R	8.5	8.8	72	2.0	455	1.40	12.1	5.7	44	49	7.9	17.7	2.05	0.55	13.7	1.16	2.61
26	A	7.1	11.1	109	0.5	520	1.78	5.5	5.1	54	84	11.1	33.2	1.13	0.60	21.6	1.96	5.97
	T	8.7	9.1	73	0.4	500	–	6.0	4.0	68	71	9.1	17.6	1.02	0.39	19.9	1.35	2.61
	R	8.8	8.8	70	0.5	490	1.80	10.7	4.4	67	72	10.7	21.4	1.78	0.42	19.7	1.55	3.11
27	A	9.1	8.1	64	1.0	590	1.26	11.6	3.3	66	86	17.0	39.7	1.89	0.31	23.0	2.40	5.65
	T	8.2	9.4	81	0.4	620	–	12.5	4.4	58	78	12.8	26.1	2.26	0.46	23.1	2.02	4.09
	R	8.1	9.5	82	0.3	–	1.38	11.1	7.3	62	69	–	–	1.98	0.75	20.2	–	–
28	A	6.6	11.9	126	1.3	540	0.90	162.0	13.1	31	79	14.7	49.0	31.6	1.68	29.0	2.87	8.41
	T	7.4	10.3	97	0.4	650	–	8.6	1.8	60	62	7.1	22.3	1.68	0.20	19.9	1.19	3.79
	R	7.7	9.8	89	0.4	–	1.40	8.9	4.7	61	76	–	–	1.65	0.50	23.2	–	–
29	A	9.4	7.1	55	9.0	370	0.75	24.7	4.4	81	83	31.1	89.7	3.78	0.39	20.9	4.12	11.95
	T	7.9	9.7	86	0.5	440	–	12.3	4.2	63	65	43.9	64.8	2.26	0.44	19.6	7.03	10.32
	R	7.7	9.1	83	0.3	–	0.74	13.6	25.0	64	74	–	–	2.43	2.58	21.9	–	–
30	A	7.5	10.3	95	0.2	570	1.10	11.7	8.2	68	79	9.6	34.2	2.26	0.91	25.0	1.62	5.72
	T	7.1	11.1	108	0.6	470	–	>170.0	9.4	14	65	13.1	35.9	>32.8	1.11	22.0	2.37	6.42
	R	6.9	11.4	114	0.3	–	0.70	>200.0	10.7	37	58	–	–	>38.5	1.29	20.1	–	–
31	A	7.9	10.5	94	0.0	530	1.37	36.1	3.8	61	68	8.5	34.2	6.97	0.42	21.6	1.43	5.77
	T	9.9	7.9	56	0.2	535	–	6.4	2.4	83	87	15.1	74.1	1.00	0.21	22.2	2.04	10.04
	R	9.6	8.0	58	0.3	–	1.50	4.7	2.4	85	89	–	–	0.73	0.21	22.7	–	–
32	A	7.0	11.4	114	0.2	545	0.98	292.0	12.5	31	73	9.8	46.8	62.63	1.54	25.7	1.80	8.69
	T	8.7	9.4	76	0.1	500	–	90.0	2.8	63	69	13.7	41.4	15.84	0.28	20.0	2.13	6.34
	R	8.6	9.3	75	0.1	–	1.00	44.0	4.2	62	67	–	–	7.57	0.41	18.9		–
33	A	6.1	12.6	143	Oily	700	0.85	>1240.0	–	9	87	24.3	113	>301.0	–	34.6	5.12	23.92
	T	6.5	12.2	131	Oily	590	–	>1240.0	221.0	20	105	25.3	119	>285.0	27.72	39.6	5.04	23.76
	R	6.6	12.1	127	Oily	–	0.85	>1240.0	166.0	22	97	–	–	>277.0	21.23	35.6	–	–
34	A	9.4	7.4	55	2.7	440	0.60	19.6	5.4	62	62	22.3	48.7	2.96	0.47	15.4	2.94	6.37
	T	9.8	8.0	55	1.0	460	–	14.8	3.9	58	56	14.5	41.2	2.24	0.34	14.4	1.92	5.40
	R	10.1	7.3	50	1.9	–	0.70	18.2	5.1	63	62	–	–	2.68	0.43	15.3	–	–
35	T	8.8	8.7	70	0.2	440	0.96	2.5	5.5	77	85	17.7	69.0	0.42	0.53	23.3	2.58	10.05
	R	9.3	7.5	57	0.2	440	0.99	3.8	9.6	84	91	13.7	43.6	0.59	0.85	23.1	1.84	5.89

[a] Units are described in Table II-2.

[b] Temperature measured at sampling point near end of 10-minute-on period.

[c] Modified EPA procedure.

Table II-4. Qualitative Summary of Tuning Effects on Emissions From Residential Units – Phase II Units

Unit	Smoke Number, 9th minute		CO$_2$, percent		Incremental Change in Efficiency, %	Change in Pollutant Emission Factor[a]				
									Particulate	
	As Found	Tuned	As Found	Tuned		CO	HC	NO$_x$	Filterable	Total
23	0.3	0.5	9.2	9.9	+0.6	+	–		–	+
24	0.4	0.7	7.1	8.9	+8.8	–	–		+	+
25	1.0	1.7	8.4	9.4	+2.6	–	+	–	+	–
26	0.5	0.4	7.1	8.7	+3.1	+	–	+	–	–
27	1.0	0.4	9.1	8.2	–2.6	+	+	–	–	–
28	1.3	0.4	6.6	7.4	–1.7	b	–	–	–	–
29	9.0	0.5	9.4	7.9	–3.9	–		–	+	–
30	0.2	0.6	7.5	7.1	0	b	+	–	+	
31	0.0	0.2	7.9	9.9	+2.9	–	–	+	+	+
32	0.2	0.1	7.0	8.7	+4.3	–	–		+	–
33	Oily	Oily	6.1	6.5	+6.3	c	b	+	–	–
34	2.7	1.0	9.4	9.8	+0.1	–	–	–	–	–

[a] + and – indicate an increase or decrease exceeding 5 percent.
[b] Change in emission factor not available due to absence of one measurement.
[c] Change in emission not measureable; both values exceeded instrument range.

Table II-5. Mean Emission Factors and Standard Deviations, for Cyclic Runs – Phases I and II

Units	Condition	Phase	Number of Units in Sample	Bacharach[a] Smoke No.		Emission Factors, lb/1000 gal													
						Gaseous Emissions						Particulate Emissions							
												EPA Procedure				Modified EPA Procedure			
						CO		HC		NO_x (as NO_2)		Filterable		Total		Filterable		Total	
				Mean	S.D.	Mean	S.D.	Mean	S.D.	Mean	S.D.	Mean	S.D.	Mean	S.D.	Mean	S.D.	Mean	S.D.
All Units	A	I	20	b	b	>11.9	>27.8	8.4	26.1	16.9	4.3	–	–	–	–	3.4	4.0	9.6	12.3
		II	12	b	b	>39.1	>85.1	0.8[c]	0.5	23.6	5.4	1.4	0.9	6.8	5.9	2.3	1.3	7.7	5.7
		I + II	32	b	b	>22.1	>56.8	5.7	21.1	19.4	5.7	–	–	–	–	2.9	3.1	8.9	10.2
	T	I	20	b	b	> 9.1	>18.7	3.3	11.2	18.2	4.7	–	–	–	–	2.2	1.7	7.1	6.8
		II	13	b	b	>26.9	>78.1	2.5	7.6	21.5	6.4	1.5	1.5	6.3	5.4	2.5	1.7	7.4	5.6
		I + II	33	b	b	>16.4	>51.4	3.0	9.7	19.5	5.6	–	–	–	–	2.3	1.7	7.2	6.2
	R	I	20	b	b	> 8.8	>17.3	1.8	2.8	18.5	4.6	–	–	–	–	–	–	–	–
		II	13	b	b	>26.4	>76.2	2.3	5.7	21.1	5.2	–	–	–	–	–	–	–	–
		I + II	33	b	b	>15.7	>40.3	2.0	4.2	19.6	4.9	–	–	–	–	–	–	–	–
All Units Except Those in Need of Replacement[d]	A	I	18	4.2	2.2	3.2	4.5	0.65	0.40	17.7	3.3	–	–	–	–	2.7	3.0	5.9	3.2
		II	11	1.4	2.4	15.3	22.5	0.83	0.51	22.6	4.3	1.2	0.7	5.2	2.5	2.1	1.0	6.2	2.7
		I + II	29	3.2	2.6	7.8	15.2	0.72	0.45	19.6	4.4	–	–	–	–	2.4	1.3	6.0	3.0
	T	I	18	1.8	1.0	3.5	5.2	0.67	0.42	19.1	3.6	–	–	–	–	2.2	1.7	5.4	2.3
		II	12	0.7	0.5	>5.4	>10.2	0.44	0.24	20.0	3.5	1.4	1.5	5.0	2.8	2.3	1.6	6.0	2.9
		I + II	30	1.3	1.0	4.3	7.6	0.57	0.37	19.5	3.5	–	–	–	–	2.2	1.6	5.7	2.5
	R	I	18	1.2	0.6	3.5	4.5	0.85	0.59	19.3	4.0	–	–	–	–	–	–	–	–
		II	12	0.6	0.6	>5.5	>11.8	0.73	0.65	19.8	3.0	–	–	–	–	–	–	–	–
		I + II	30	0.9	0.6	4.3	8.1	0.80	0.61	19.5	3.6	–	–	–	–	–	–	–	–

[a] Smoke data at 5-minute point.

[b] Oily smoke spots prevented obtaining meaningful averages.

[c] Value low because no data were obtained for HC emissions from Unit 33 in Condition A.

[d] Units not included were Units 5, 20, and 33.

The effects of tuning on the gaseous emissions were generally inconsistent. Tuning reduced CO, HC, and NO_x emissions for about one-half of the units. Total particulate was reduced for eight units, but filterable particulate was reduced for only six units.

Both before and after tuning, raw oil was found on the smoke spot for Unit 33. Also, this unit operated with CO in excess of the instrument scale limit of 1240 ppm and with extremely high HC. Hence, this unit is considered to be in need of replacement or major renovation and would be so identified by competent servicemen. Because of the distortion of average emissions by the data from this unit, these data are omitted from data summaries and statistical tabulations where equipment features are examined. (This procedure was also followed in Phase I, where 2 of the 20 units were identified to need replacement.)

Table II-5 provides a comparison of average emissions for Phase I and II units in the as-found and tuned condition. Separate summaries are presented showing (1) all units and (2) all units except those in need of replacement or renovation (identified by the presence of oil on the smoke spots). Table II-6 shows the percentage reduction in emissions obtained by (1) replacement of poor units and (2) replacement of poor units plus tuning of remaining units.* A large reduction in average emissions of CO, HC, and particulate is observed when the poorly performing units are eliminated from the data. Although some shifts are noted with tuning of the remaining units, the overall effect on emissions of tuning these units is considered minor except for smoke.

Table II-6. Reduction of Mean Emissions Upon Replacement and Tuning of Residential Units

	Replacement Only	Replacement Plus Tuning
Smoke	–[a]	59%
CO	>65%	>81%
HC	87%	90%
NO_x	No change	No change
Filterable Particulate[b]	17%	24%
Total Particulate[b]	33%	36%

[a] Not meaningful, as smoke spots of units eliminated were identified as "oily" and not evaluated numerically.

[b] By modified EPA procedure.

Fuel. Table II-5 also shows average emissions for the reference fuel runs. (Insufficient particulate measurements were included for the reference fuel runs to make comparisons of particulate emissions meaningful.) Only slight shifts are noted by comparing the averages for the tuned runs and reference fuel runs. Thus, the effect on emissions of differences between the house fuels and the reference fuel is considered minor.

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*Values are based on the distribution of "poor" units found in the Phase I and II studies; that is, 3 poor units in a total sample of 32 oil-fired units.

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*Values are based on the distribution of "poor" units found in the Phase I and II studies; that is, 3 poor units in a total sample of 32 oil-fired units.

Comparison of Emissions for Different Equipment Features

In order to determine whether certain features of burner design or of installation type have an important bearing on emissions characteristics, several comparisons were made using the cyclic runs for Phase I and Phase II as the basis.

The following tables show comparisons of mean emissions from gun-burner units (excluding units in need of replacement) by equipment categories normally of interest to the oil-heating industry:

Table II-7.	Matched Units Versus Conversion Units
Table II-8.	Furnaces Versus Boilers
Table II-9.	Conventional Versus Flame-Retention Combustion Heads
Table II-10.	Effect of Burner Age.

Pertinent observations regarding each comparison are noted below, especially for the tuned or reference runs.*

Matched Units Versus Conversion Units. A matched unit is defined as a burner-furnace or burner-boiler unit that is factory matched and supplied as a combination, whereas a conversion burner refers to a furnace or boiler installation incorporating a burner other than the model supplied by the factory. The comparison in Table II-7 shows that the smoke from matched units was lower than from conversion units for the as-found condition (2.9 versus 3.7), but not for the tuned condition. Conversion units had lower CO emissions for all conditions but had higher HC emissions for the tuned and reference-fuel conditions. Particulate emissions were not significantly different for the two types of units.

Furnaces Versus Boilers. Table II-8 shows that furnaces operated at slightly lower smoke levels than boilers. Conversely, mean CO and particulate emissions for the 11 furnaces were consistently and appreciably higher than for the 16 boilers; however, the mean CO levels for the furnaces are not considered excessive. The higher CO level with furnaces is surprising, in view of higher combustion chamber temperatures generally expected for furnaces. Mean NO_x emissions for the furnaces were slightly but consistently higher than for the boilers. The higher NO_x levels with furnaces probably reflects the higher combustion chamber temperatures.

Conventional Versus Flame-Retention Combustion Heads. The comparisons in Table II-9 indicate higher mean emissions of smoke, CO, HC, and filterable particulate for the 16 burners having conventional combustion heads than for the eight burners having flame-retention heads. Although the conventional burners showed the largest reduction in smoke upon tuning (from 3.7 to 1.2), filterable and total particulate emissions from these units showed only a slight reduction from the tuning. The three Shell head burners had emissions similar to those of the flame-retention heads.

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*Particulate measurements for the reference-fuel condition were only done on the four follow-up units in Phase II; thus, particulate data from reference runs are not included in statistical tabulations.

Table II-7. Mean Emission Factors and Standard Deviations for Matched Units and Conversion Units for Cyclic Runs, Phase I and II Units[a]

Unit Type and Condition		Number of Units in Sample	Bacharach Smoke No. at 5 Min		Emission Factors, lb/1000 gal									
					Gaseous Emissions						Particulate Emissions[b]			
					CO		HC		NO_x (as NO_2)		Filterable		Total	
			Mean	S.D.	Mean	S.D.	Mean	S.D.	Mean	S.D.	Mean	S.D.	Mean	S.D.
							Units							
Matched	A	21	2.9	2.6	9.8	17.3	0.69	0.45	20.1	4.7	2.4	2.7	6.4	3.4
	T	22	1.2	0.9	4.4	8.2	0.47	0.26	19.5	3.5	2.2	1.5	5.8	2.5
	R	22	0.9	0.6	4.3	9.1	0.72	0.53	19.7	3.3	–	–	–	–
							Units							
Conversion	A	7	3.7	3.2	1.0	0.8	0.65	0.25	19.0	3.0	2.4	1.2	5.1	1.5
	T	7	1.5	0.9	2.9	5.8	0.75	0.36	20.2	2.8	2.4	2.6	5.6	3.0
	R	7	1.0	0.6	3.3	4.4	0.90	0.72	20.1	3.3	–	–	–	–

[a] Excluding units in need of replacement.

[b] Particulate by modified EPA procedure.

Table II-8. Mean Emission Factors and Standard Deviations for Furnaces and Boilers for Cyclic Runs, Phase I and II Units[a]

Unit Type and Condition		Number of Units in Sample	Bacharach Smoke No. at 5 Min		Emission Factors, lb/1000 gal									
					Gaseous Emissions						Particulate Emissions[b]			
					CO		HC		NO_x (as NO_2)		Filterable		Total	
			Mean	S.D.	Mean	S.D.	Mean	S.D.	Mean	S.D.	Mean	S.D.	Mean	S.D.
							Furnaces							
Furnaces	A	11	2.7	3.0	17.2	21.5	0.86	0.52	22.6	4.1	3.4	3.6	7.2	3.5
	T	12	1.0	0.8	8.5	10.7	0.43	0.25	20.5	2.8	2.6	1.8	6.8	2.6
	R	12	0.8	0.6	7.9	11.7	0.83	0.66	20.5	2.4	–	–	–	–
							Boilers							
Boilers	A	17	3.4	2.6	1.4	2.7	0.56	0.27	18.0	3.4	1.8	1.0	5.3	2.5
	T	17	1.4	0.9	1.1	1.2	0.46	0.33	19.2	3.6	1.9	1.6	4.9	2.3
	R	17	0.9	0.6	1.4	1.6	0.71	0.53	19.3	3.7	–	–	–	–

[a] Excluding units in need of replacement.

[b] Particulate by modified EPA procedure.

Table II-9. Mean Emission Factors and Standard Deviations for Burners With Various Combustion-Head Designs for Cyclic Runs, Phase I and II Units[a]

Combustion Head	Condition	Number of Units in Sample	Bacharach Smoke No. at 5 Min		Emission Factors, lb/1000 gal									
					Gaseous Emissions						Particulate Emissions[b]			
					CO		HC		NO_x (as NO_2)		Filterable		Total	
			Mean	S.D.	Mean	S.D.	Mean	S.D.	Mean	S.D.	Mean	S.D.	Mean	S.D.
Conventional	A	17	3.7	3.0	9.9	17.7	0.70	0.42	19.8	4.2	2.9	3.1	6.7	3.3
Shell	A	3	2.8	2.9	0.9	0.9	0.69	0.12	18.9	3.8	2.3	0.6	5.5	1.0
Flame retention	A	8	2.1	1.9	5.3	12.5	0.63	0.48	20.2	5.0	1.6	0.8	4.9	2.7
Conventional	T	18	1.3	0.9	5.9	9.3	0.59	0.33	20.7	2.9	2.8	1.9	6.8	2.4
Shell	T	3	1.7	1.2	0.9	0.8	0.60	c	18.3	3.1	1.3	c	2.6[d]	c
Flame retention	T	8	1.0	0.6	1.1	0.9	0.39	0.18	18.1	3.8	1.3	0.6	3.9	1.6
Conventional	R	18	0.9	0.6	5.8	10.0	0.84	0.69	20.3	3.4	–	–	–	–
Shell	R	3	1.0	0.6	1.6	0.3	0.81	0.39	19.2	4.0	–	–	–	–
Flame retention	R	8	0.8	0.6	1.1	0.7	0.54	0.18	18.8	2.9	–	–	–	–

[a] Excluding units in need of replacement.

[b] Particulate by modified EPA procedure.

[c] Less than three data available – standard deviation not meaningful.

[d] Based on only one data point.

Table II-10. Mean Emission Factors and Standard Deviations by Burner Age, Phase I and II Units[a]

Burner Age, years	Condition	Number of Units in Sample	Bacharach Smoke No. at 5 Min		Emission Factors, lb/1000 gal									
					Gaseous Emissions						Particulate Emissions[b]			
					CO		HC		NO_x (as NO_2)		Filterable		Total	
			Mean	S.D.	Mean	S.D.	Mean	S.D.	Mean	S.D.	Mean	S.D.	Mean	S.D.
5-Year Cut														
<5	A	16	3.0	2.5	11.7	19.6	0.84	0.44	20.0	5.0	2.4	2.8	6.2	3.6
≥5	A	12	3.3	2.7	2.2	1.6	0.47	0.16	19.6	3.2	2.4	1.3	5.8	1.9
<5	T	17	1.1	0.8	2.8	4.8	0.51	0.25	19.7	3.6	1.8	1.0	5.2	2.5
≥5	T	12	1.5	0.6	5.6	9.5	0.57	0.25	19.8	2.3	2.9	1.9	6.4	1.7
<5	R	17	0.8	0.5	2.6	3.4	0.68	0.32	19.3	2.9	–	–	–	–
≥5	R	12	1.0	0.5	6.1	10.8	0.87	0.47	20.5	3.5	–	–	–	–
15-Year Cut														
<15	A	22	2.8	2.2	9.0	16.6	0.71	0.37	19.7	4.6	2.3	2.6	5.9	3.1
≥15	A	6	4.4	4.0	2.7	2.0	0.56	0.21	20.1	3.1	2.6	1.5	6.6	2.6
<15	T	23	1.3	0.8	2.6	4.1	0.47	0.21	19.3	3.4	1.8	0.9	5.0	2.2
≥15	T	6	1.2	0.7	9.1	14.0	0.76	0.36	21.4	1.6	3.7	2.5	8.1	2.2
<15	R	23	0.9	0.5	2.4	3.0	0.62	0.29	19.4	3.3	–	–	–	–
≥15	R	6	0.8	0.6	10.6	15.8	1.28	0.65	21.4	2.1	–	–	–	–

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[a] Excluding units in need of replacement.

[b] Particulate by modified EPA procedure.

Effect of Burner Age. Table II-10 summarizes emission by burner age for two age cuts: 5 and 15 years. For the 5-year cut, it compares mean emissions for 17 burners less than 5 years old with 12 burners 5 years old or older. For the 15-year cut, it compares 23 burners less than 15 years old with 6 burners 15 years old or older. Smoke was consistently lower for newer burners, considering the 5-year cut; for the 15-year cut, newer burners had lower smoke for the as-found condition only. For the tuned condition, mean CO and particulate levels of the newer burners were consistently and appreciably less. Conversely, for the as-found condition, CO was lower for the older burners. Mean HC emissions were generally lower for newer burners in the tuned condition but higher for newer burners in the as-found condition.

Effect of Burner Age on Smoke and Particulate Emissions When Tuning. Figures II-4 and II-5 show the change in smoke level, filterable particulate, and total particulate upon tuning for 5-year increments of burner age. Table II-11 presents the same data in the form of percent reduction of each of these emissions for the tuned condition compared with the as-found condition. These data show that tuning of the newer burners (those less than 15 years old) reduced both smoke and particulate emissions. However, for the older burners (which showed the greatest reduction in smoke), the tuning actually resulted in an increase in particulate emissions.

Statistical Ranking of Equipment and Fuel Variables

In addition to the statistical analysis of the data presented above, another statistical treatment of the data was used to rank the influence of important variables on emissions.

Basically, this technique consists of separating the data into two sets for each variable considered and then ranking the variables by the differences between the two sets. Where more than one division of the data was possible (e.g., for continuous variables such as burner age), the data are divided at the point that produces two sets with the maximum difference. The sets of data for each variable are compared primarily on the basis of mean values, but the calculation is weighted by the number of values in each set and the scatter of the data.

The most significant variables insofar as effecting the pollutant being considered can be regarded as those that produce the largest differences when the data are separated into two sets on that variable.

An analysis of this type was made on the emission data as follows:

Emission Data

Smoke
CO
HC
NO_x
Filterable particulate (by modified EPA procedure)
Total particulate (by modified EPA procedure)

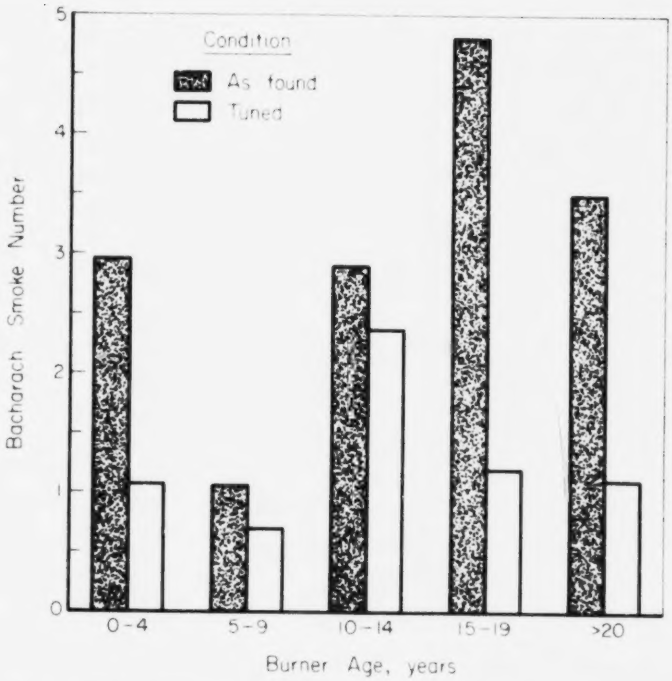

Figure II-4. Effect of Tuning on Smoke, by Burner Age

Table II-11. Effect of Tuning on Smoke and Particulate Emissions, by Burner Age

Burner Age, years	No. of Units	Change of Emissions Upon Tuning, percent[a]		
		Smoke	Particulate	
			Filterable	Total
0-4	17	-64	-24	-16
5-9	2	-33	-16	-14
10-14	4	-18	-29	- 7
15-19	4	-75	+44	+ 2
⩾20	2	-69	+43	+82

[a] Minus indicates reduction of emission upon tuning; plus indicates an increase in emissions upon tuning.

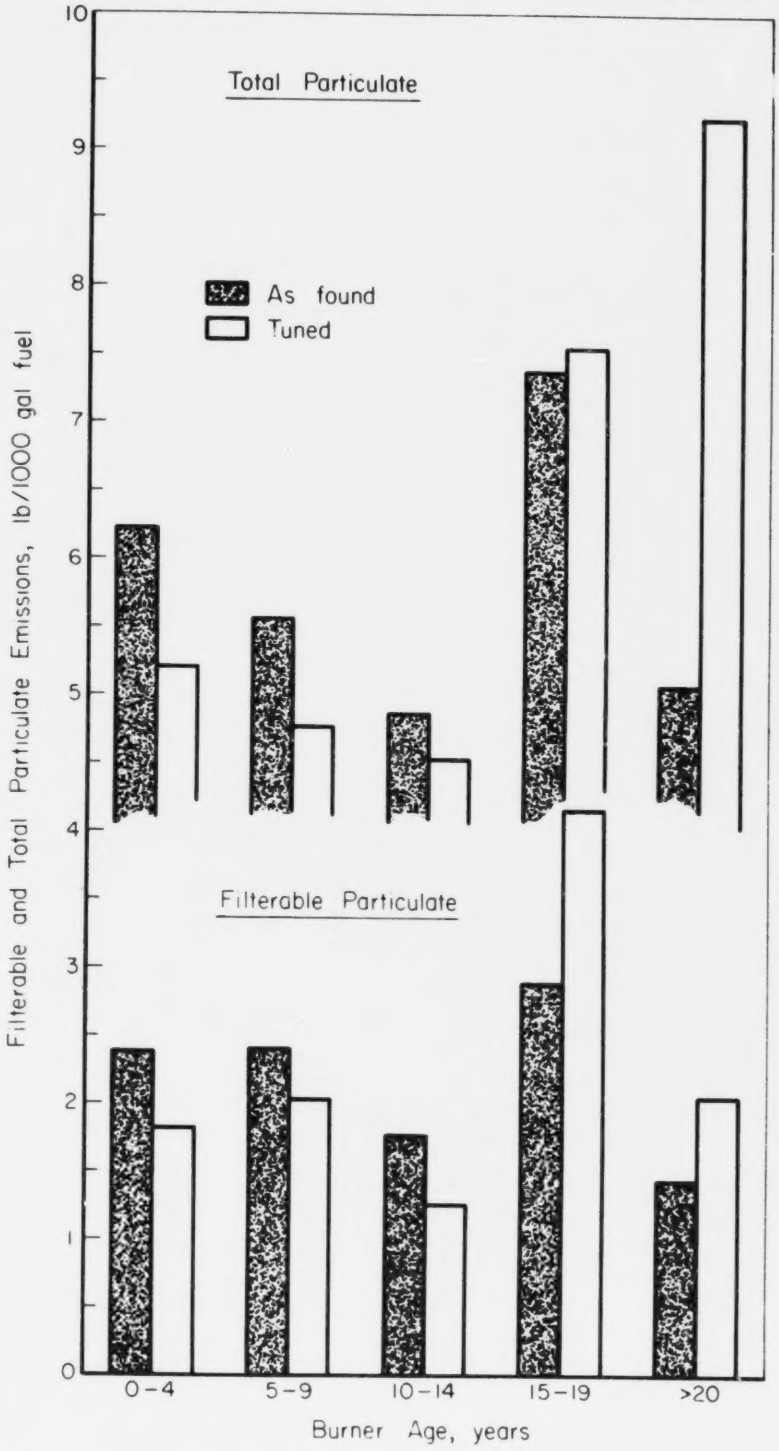

Figure II-5. Effect of Tuning on Particulate Emissions by Burner Age Modified EPA Procedure.

Conditions

A – as found

T – tuned

R – reference runs

A and T – together

Variables

Unit type – matched or conversion

System type – furnace or boiler

System age – by 5-year increments

Burner type – conventional (CH), Shell head (SH), or flame-retention head (FRH)

Burner age – by 5-year increments

Firing rate – by fixed increments, with breaks at 1.00, 1.35, 1.65, 2.00, and 3.00 gph

Fuel API gravity – by one degree API increments

Condition – A or T (this variable was only included when all as-found and tuned data were considered together).

For this analysis the following units were not included:

No. 21 and 22 – These were gas-fired units.

No. 19 and 20 – These were not gun burners, and the one of each type included in the program was not considered sufficient for statistical analyses.

No. 5, 20, and 33 – These were units in need of replacement, which would not reflect equipment and fuel variables properly.

No. 35 for Condition A – This was the lab unit, which had no equivalent prior operation to define a normal "as-found" condition.

Tables II-12 through II-15 list the results of the analyses described above for the A, T, R, and A + T conditions, respectively. For each table and emission, the variables are listed in order of their decreasing significance.

A difficulty is encountered in interpreting the results of this analysis for variables with more than two values, because the analysis may split these variables at different points when considering the different emissions. For example, for the as-found condition, the best split on firing rate was at 1.35 gph for filterable particulate and at 1.00 gph for total particulate.

As-Found Conditions. Table II-12 shows the ranking of variables in terms of their significance in affecting emissions for the as-found condition. Examination of this table permits the following observations:

- System type and firing rate generally received high rankings as having a major influence on most emissions. Unit type and system age generally ranked low.

- The units having higher firing rates (with a split at 1.0 or 1.35 gph) had lower emissions of all pollutants except smoke. The smoke data was split at 3.0 gph, with the smaller units outperforming the two larger units.

- High-turbulence combustion heads (flame-retention and Shell heads) generally had lower emissions than conventional head burners. Exceptions to this were NO_x for flame-retention head units and HC for Shell head units.

- Although fuel gravity appeared near the mid-point on each ranking (3rd, 4th, or 5th), the influence was varied. That is, lighter fuels (33.0 to 36.9 API gravity) produced lower smoke, CO, HC, and total particulate emissions, but heavier fuels (30.0 to 32.9 API gravity) produced lower NO_x and filterable particulate emissions. Hence, the overall influence of fuel was interpreted as not significant in affecting emissions for units in the as-found condition.

Tuned Condition. Examination of Table II-13 showing the ranking of variables for the tuned condition shows that:

- Burner age and system age generally appeared near the top of the lists as having the greatest influence on emissions; unit type generally had a low influence on emissions.

- Newer units (both burner age, and system age) had lower emissions than older units. The best splits on age were at 10 years for smoke and 15 years for other emissions.

- High-turbulence head burners generally produced lower emissions than burners with conventional heads. However, smoke emission from Shell head burners was higher than from the conventional and flame-retention head burners.

- Fuel gravity generally did not have a high ranking and the influence was varied. That is, units firing lower gravity fuels produced less smoke, CO, HC, and filterable particulate but more NO_x and total particulate.

Reference Condition. Table II-14 showing the ranking of variables for the reference fuel runs (in the tuned condition) produced conclusions generally agreeing with conclusions for the tuned condition.

Combined Data for the As-Found and Tuned Conditions. Table II-15 shows the ranking of variables when all as-found and tuned runs are combined and when unit condition (as-found

(Text continues on page II-36.)

Table II-12. Statistical Ranking of Variables for the As-Found Condition

Units for mean values and standard deviations are lb/1000 gal.

Smoke				CO				HC			
Variable	**Split**	**Mean**	**S.D.**	**Variable**	**Split**	**Mean**	**S.D.**	**Variable**	**Split**	**Mean**	**S.D.**
Firing Rate				System Type				Burner Age			
	⩽3.00 gph	2.9	2.0		Boiler	1.4	2.6		⩾5 years	0.47	0.43
	>3.00 gph	6.3	0.3		Furnace	17.2	20.5		<5 years	0.84	0.24
System Age				Firing Rate				System Type			
	<15 years	2.6	2.1		⩾1.00 gph	4.5	10.5		Boiler	0.56	0.26
	⩾15 years	4.3	3.6		<1.00 gph	17.1	21.9		Furnace	0.86	0.50
Burner Type				Burner Age				Fuel Gravity			
	FRH,SH	2.3	2.1		⩾5 years	2.2	1.9		33.0-36.9	0.57	0.27
	CH	3.7	2.9		<5 years	11.7	19.0		30.0-32.9	0.79	0.49
Burner Age				Fuel Gravity				Firing Rate			
	<15 years	2.8	2.2		33.0-36.9	3.0	3.4		⩾1.00 gph	0.62	0.34
	⩾15 years	4.4	4.1		30.0-32.9	12.3	20.9		<1.00 gph	0.86	0.52
Fuel Gravity				System Age				System Age			
	32.0-36.9	2.6	2.6		⩾10 years	2.7	4.9		⩾10 years	0.58	0.29
	30.0-31.9	3.9	2.8		<10 years	11.9	20.2		<10 years	0.77	0.48
System Type				Unit Type				Burner Type			
	Furnace	2.7	2.9		Conversion	1.0	0.7		FRH	0.63	0.45
	Boiler	3.4	2.5		Matched	9.8	16.9		CH,SH	0.70	0.39
Unit Type				Burner Type				Unit Type			
	Matched	2.9	2.5		FRH,SH	4.1	10.7		Conversion	0.65	0.23
	Conversion	3.7	3.0		CH	9.9	17.2		Matched	0.69	0.44

Table II-12. (Continued)

NO_x				Filterable Particulate				Total Particulate			
Variable	**Split**	**Mean**	**S.D.**	**Variable**	**Split**	**Mean**	**S.D.**	**Variable**	**Split**	**Mean**	**S.D.**
System Type				System Type				Firing Rate			
	Boiler	18.0	3.3		Boiler	1.8	0.9		≥1.00 gph	5.3	2.8
	Furnace	22.6	4.0		Furnace	3.4	3.4		<1.00 gph	8.3	2.7
Firing Rate				Firing Rate				System Type			
	>1.35 gph	17.9	3.2		>1.35 gph	1.7	1.1		Boiler	5.3	2.2
	≤1.35 gph	21.3	4.5		≤1.35 gph	3.0	3.0		Furnace	7.7	3.3
Fuel Gravity				Burner Type				Burner Type			
	30.0-31.9	18.2	4.2		FRH,SH	1.8	0.8		FRH,SH	5.1	2.3
	32.0-36.9	20.9	4.1		CH	2.9	3.0		CH	6.2	3.2
Unit Type				Fuel Gravity				Fuel Gravity			
	Conversion	19.0	2.8		30.0-32.9	2.0	1.0		34.0-36.9	4.8	1.2
	Matched	20.1	4.5		33.0-36.9	2.8	3.3		30.0-33.9	6.5	3.3
System Age				Burner Age				Unit Type			
	<5 years	19.2	5.0		<15 years	2.3	2.6		Conversion	5.1	1.4
	≥5 years	20.2	3.8		≥15 years	2.6	1.4		Matched	6.4	3.3
Burner Type				System Age				System Age			
	SH	18.9	3.1		≥5 years	2.3	1.1		≥5 years	5.6	2.2
	CH,FRH	19.9	4.4		<5 years	2.5	3.4		<5 years	6.8	4.0
Burner Age				Unit Type				Burner Age			
	≥10 years	19.5	3.3		Conversion	2.4	1.1		<15 years	5.9	3.1
	<10 years	20.0	4.8		Matched	2.4	2.6		≥15 years	6.6	2.8

Table II-13. Statistical Ranking of Variables for the Tuned Condition

Units for mean values and standard deviations are lb/1000 gal.

Smoke				CO				HC			
Variable	**Split**	**Mean**	**S.D.**	**Variable**	**Split**	**Mean**	**S.D.**	**Variable**	**Split**	**Mean**	**S.D.**
System Age				System Type				System Age			
	<10 years	1.0	0.7		Boiler	1.1	1.2		<15 years	0.45	0.23
	≥10 years	1.6	1.0		Furnace	8.5	10.2		≥15 years	0.73	0.38
Burner Age				Firing Rate				Burner Age			
	<10 years	1.0	0.8		≥1.00 gph	1.7	3.5		<15 years	0.47	0.23
	≥10 years	1.7	1.0		<1.00 gph	8.9	10.6		≥15 years	0.76	0.44
System Type				Fuel Gravity				Unit Type			
	Furnace	1.0	0.8		30.0-33.9	2.2	4.7		Matched	0.47	0.25
	Boiler	1.4	0.9		34.0-36.9	8.9	12.6		Conversion	0.75	0.33
Firing Rate				Burner Age				Fuel Gravity			
	>1.35 gph	1.0	0.5		<15 years	2.6	4.1		30.0-30.9	0.34	0.20
	≤1.35 gph	1.4	1.0		≥15 years	9.1	14.0		31.0-36.9	0.58	0.30
Fuel Gravity				Burner Type				Burner Type			
	30.0-34.9	1.2	0.9		FRH,SH	1.0	0.8		FRH	0.39	0.17
	35.0-36.9	1.8	0.9		CH	5.9	9.0		CH,SH	0.59	0.32
Burner Type				System Age				Firing Rate			
	CH,FRH	1.2	0.9		<15 years	2.9	4.4		>1.35 gph	0.45	0.25
	SH	1.7	1.0		≥15 years	6.3	11.9		≤1.35 gph	0.60	0.32
Unit Type				Unit Type				System Type			
	Matched	1.2	0.9		Conversion	2.9	5.3		Furnace	0.49	0.24
	Conversion	1.5	0.8		Matched	4.4	8.0		Boiler	0.56	0.32

Table II-13. (Continued)

NO_x				Filterable Particulate				Total Particulate			
Variable	**Split**	**Mean**	**S.D.**	**Variable**	**Split**	**Mean**	**S.D.**	**Variable**	**Split**	**Mean**	**S.D.**
Burner Type				Burner Age				Burner Type			
	FRH,SH	18.2	3.4		<15 years	1.8	1.0		FRH,SH	3.7	1.6
	CH	20.7	2.9		≥15 years	3.7	2.7		CH	6.8	2.3
Fuel Gravity				Burner Type				Burner Age			
	35.0-36.9	16.5	1.5		FRH,SH	1.3	0.5		<15 years	5.0	3.1
	30.0-34.9	20.1	3.3		CH	2.8	1.9		≥15 years	8.1	2.3
System Age				Firing Rate				System Type			
	<15 years	19.0	3.2		≥1.00 gph	1.7	1.4		Boiler	4.9	2.2
	≥15 years	21.3	3.2		<1.00 gph	3.1	1.8		Furnace	6.8	2.5
Burner Age				System Age				System Age			
	<15 years	19.3	3.5		<15 years	1.9	1.0		<15 years	5.2	2.3
	≥15 years	21.4	1.6		≥15 years	3.0	2.6		≥15 years	6.9	3.0
Firing Rate				Fuel Gravity				Firing Rate			
	>1.35 gph	18.8	3.6		30.0-30.9	1.6	0.4		≥1.00 gph	5.2	2.5
	≤1.35 gph	20.4	3.0		31.0-36.9	2.4	1.9		<1.00 gph	6.7	2.3
System Type				System Type				Fuel Gravity			
	Boiler	19.2	3.5		Boiler	1.9	1.6		32.0-36.9	5.4	2.6
	Furnace	20.5	2.7		Furnace	2.6	1.7		30.0-31.9	6.3	2.4
Unit Type				Unit Type				Unit Type			
	Matched	19.5	3.4		Matched	2.2	1.5		Conversion	5.6	2.7
	Conversion	20.2	2.6		Conversion	2.4	2.2		Matched	5.8	2.5

Table II-14. Statistical Ranking of Variables for the Reference Condition

Units for the mean values and standard deviations are lb/1000 gal.

Smoke				CO				HC			
Variable	Split	Mean	S.D.	Variable	Split	Mean	S.D.	Variable	Split	Mean	S.D.
Burner Age				Burner Age				Burner Age			
	<10 years	0.8	0.5		<15 years	2.4	3.1		<15 years	0.62	0.31
	≥10 years	1.1	0.7		≥15 years	10.6	16.2		≥15 years	1.28	1.15
System Age				Firing Rate				System Age			
	<10 years	0.8	0.5		≥1.00 gph	1.9	1.8		<15 years	0.59	0.29
	≥10 years	1.0	0.6		<1.00 gph	8.9	12.4		≥15 years	1.12	0.86
Burner Type				System Type				Firing Rate			
	FRH	0.8	0.5		Boiler	1.4	1.6		>1.35 gph	0.51	0.27
	CH,SH	0.9	0.6		Furnace	7.9	11.2		≤1.35 gph	0.95	0.68
Firing Rate				Burner Type				Burner Type			
	>1.35 gph	0.8	0.5		FRH,SH	1.2	0.7		FRH	0.54	0.17
	≤1.35 gph	0.9	0.6		CH	5.8	9.7		CH,SH	0.84	0.65
System Type				System Age				Unit Type			
	Furnace	0.8	0.6		<15 years	2.6	3.3		Matched	0.72	0.52
	Boiler	0.9	0.5		≥15 years	7.4	13.7		Conversion	0.90	0.67
Unit Type				Unit Type				System Type			
	Matched	0.9	0.6		Conversion	3.3	4.0		Boiler	0.71	0.51
	Conversion	1.0	0.6		Matched	4.3	8.9		Furnace	0.83	0.63

Table II-14. (Continued)

		NO_x	
Variable	**Split**	**Mean**	**S.D.**
System Age			
	<5 years	18.6	2.5
	⩾5 years	20.6	3.5
Burner Age			
	<10 years	19.2	2.9
	⩾10 years	21.0	3.9
Burner Type			
	FRH,SH	18.9	3.1
	CH	20.3	3.3
System Type			
	Boiler	19.3	3.6
	Furnace	20.5	2.3
Firing Rate			
	>2.00 gph	18.9	2.5
	⩽2.00 gph	20.0	3.7
Unit Type			
	Matched	19.7	3.3
	Conversion	20.1	3.0

Table II-15. Statistical Ranking of Variables for the As-Found and Tuned Conditions Combined

Units for mean values and standard deviations are lb/1000 gal.

Smoke				CO				HC			
Variable	**Split**	**Mean**	**S.D.**	**Variable**	**Split**	**Mean**	**S.D.**	**Variable**	**Split**	**Mean**	**S.D.**
Condition				System Type				Burner Age			
	T	1.3	0.9		Boiler	1.2	2.1		≥5 years	0.52	0.31
	A	3.1	2.7		Furnace	12.9	16.8		<5 years	0.67	0.38
Firing Rate				Firing Rate				Condition			
	≤3.00 gph	2.0	2.1		≥1.00 gph	3.1	8.0		T	0.53	0.29
	>3.00 gph	4.5	2.5		<1.00 gph	12.5	17.0		A	0.68	0.40
System Age				Burner Type				Firing Rate			
	<10 years	1.7	1.8		SH,FRH	2.6	7.6		>1.35 gph	0.52	0.27
	≥10 years	2.7	2.5		CH	7.9	13.9		≤1.35 gph	0.67	0.41
Burner Age				Unit Type				Burner Type			
	<10 years	1.9	2.0		Conversion	1.9	3.9		FRH	0.51	0.36
	≥10 years	2.7	2.5		Matched	7.1	13.5		CH,SH	0.64	0.35
Burner Type				System Age				Fuel Gravity			
	FRH	1.6	1.4		≥5 years	4.2	8.4		33.0-36.9	0.55	0.24
	CH,SH	2.4	2.4		<5 years	8.7	16.5		30.0-32.9	0.67	0.46
Fuel Gravity				Condition				System Age			
	32.0-36.9	1.9	2.0		T	4.0	7.4		<15 years	0.57	0.37
	30.0-31.9	2.6	2.5		A	7.6	15.1		≥15 years	0.69	0.34
System Type				Burner Age				System Type			
	Furnace	1.8	2.2		≥5 years	3.9	7.4		Boiler	0.56	0.29
	Boiler	2.4	2.1		<5 years	7.3	14.5		Furnace	0.67	0.43
Unit Type				Fuel Gravity				Unit Type			
	Matched	2.0	2.1		33.0-36.9	4.4	7.3		Matched	0.58	0.37
	Conversion	2.6	2.5		30.0-32.9	7.2	15.6		Conversion	0.69	0.29

Table II-15. (Continued)

NO_x				Filterable Particulate				Total Particulate			
Variable	**Split**	**Mean**	**S.D.**	**Variable**	**Split**	**Mean**	**S.D.**	**Variable**	**Split**	**Mean**	**S.D.**
System Type				Burner Type				Burner Type			
	Boiler	18.6	3.5		SH,FRH	1.6	0.7		SH,FRH	4.5	2.1
	Furnace	21.5	3.5		CH	2.9	2.5		CH	6.7	2.8
Firing Rate				System Type				Firing Rate			
	>1.35 gph	18.3	3.4		Boiler	1.9	1.3		≥1.00 gph	5.3	2.6
	≤1.35 gph	20.8	3.8		Furnace	3.0	2.7		<1.00 gph	7.4	2.6
Fuel Gravity				Firing Rate				System Type			
	35.0-36.9	17.5	2.7		>1.35 gph	1.7	1.3		Boiler	5.1	2.3
	30.0-34.9	20.0	3.8		≤1.35 gph	2.8	2.4		Furnace	7.0	3.0
Burner Type				Burner Age				Burner Age			
	SH,FRH	19.0	4.0		<15 years	2.1	2.0		<15 years	5.5	2.7
	CH	20.2	3.5		≥15 years	3.2	2.2		≥15 years	7.4	2.6
Burner Age				Fuel Gravity				Fuel Gravity			
	<15 years	17.9	8.8		30.0-30.9	1.7	0.6		34.0-36.9	4.9	1.6
	≥15 years	20.7	2.4		31.0-36.9	2.5	2.3		30.0-33.9	6.2	3.1
System Age				System Age				System Age			
	<15 years	19.4	4.0		<15 years	2.1	2.1		<15 years	5.7	2.8
	≥15 years	20.5	3.2		≥15 years	2.7	1.9		≥15 years	6.4	2.7
Unit Type				Condition				Unit Type			
	Conversion	19.6	2.8		T	2.2	1.6		Conversion	5.3	2.0
	Matched	19.8	4.0		A	2.4	2.3		Matched	6.1	2.9
Condition				Unit Type				Condition			
	T	19.7	4.2		Matched	2.3	2.1		T	5.7	2.6
	A	19.8	3.3		Conversion	2.4	1.7		A	6.1	3.0

or tuned) is considered as a variable. The interesting point in this table is the ranking of unit condition relative to other variables. Observations from this table show that:

- Unit condition generally appeared low in the ranking except for smoke and HC. Unit condition would be expected to appear high on the smoke list, because tuning was based on a smoke criteria. HC emissions were always low, so the high ranking of condition for this emission is not significant. Hence, these results confirm the earlier observation that tuning does not greatly influence emissions from generally well-performing units.
- Firing rate and burner type generally appeared high in the rankings; system age, unit type, and fuel gravity generally appeared low in the ranking.
- Units with lower firing rates produced higher emissions except for smoke. The data usually split at 1.0 to 1.35 gph.
- High-turbulence combustion heads produced lower emissions except for smoke and HC, where Shell head units did not significantly outperform conventional units.

Conclusions Related to Equipment Features and Fuel

Examination of results reported above (where emissions are compared for various equipment features and fuels) does not reveal firm guidelines for the industry to follow with regard to equipment design, service requirements, or fuel. Most variables (such as design features, tuning, and fuel gravity) had little effect on emissions.

The major influence on emissions from oil-fired industrial units was found to be the elimination (by replacement or major overhaul) of the very poorly performing units. Eliminating these units (9 percent of the units in this limited sample) reduced emissions of the total population of oil-fired units by about 50 percent. It was found that these poorly performing units were characterized by the appearance of oil on the smoke spot. This characteristic should readily be recognized by burner servicemen. Hence, an annual inspection and cleanup (already recommended by many oil-heating organizations) that includes a smoke spot evaluation should identify units producing excessive emissions. Tuning the remaining units to any specified smoke level, as has been proposed in some localities as an air pollution-control measure, does not appear to have any additional benefit insofar as reducing the mass of emissions. In fact, smoke measurements can yield a low smoke reading and, at the same time, show evidence of oil – the telltale sign of high emissions.

Apart from replacing poor units, the most significant feature insofar as its impact on emissions was the generally superior performance of units equipped with flame-retention combustion heads. Fortunately, the industry has largely adopted flame-retention head burners as the preferred modern burner design. As these units replace older conventional gun burners, the oil-heat industry will be moving in the direction of lower average emissions.

Measurements on Follow-Up Units

Measurements made in the Phase I program were on a spot basis only, with a single follow-up visit made only to two units. This approach was extended in Phase II by observing emission levels for four units during the heating season to determine the effect of time since the initial tuning. Two follow-up checks were made on Units 23, 24, 25, and 26 after approximately 2 and 4 months of operation during the heating season.

These units, selected to provide a cross section of burner types, were as follows:

Unit	Burner Type	Burner Age	System Type	Domestic Hot Water Coil
23	High-pressure gun, FRH*, 3450 rpm	< 1	Water, CI boiler	No
24	High-pressure gun	4	Forced stored air, steel furnace	No
25	High-pressure gun, FRH*, 3450 rpm	< 1	Water, steel boiler	Yes
26	High-pressure gun, Shell head	2	Steam, CI boiler	Yes

The burners were equipped with operating time clocks and cycle counters to record operating experience between visits.

For these follow-up checks, gaseous emissions were measured for the as-found condition using both the house fuel and the reference fuel. Particulate measurements were included for these units as part of the initial measurements and at the end of the season with the reference fuel.

Table II-16 shows complete measurements and emission factors for the initial runs and the two subsequent follow-up checks. Also shown in this table are emissions for Units 12 and 16 from Phase I. Emissions from these units were measured during Phase II and reported as Units 24 and 26, respectively.

Table II-17 provides a summary of the average emission factors for the follow-up units. Emission averages are shown for the four units and for three units not including Unit 25, which had unusual nozzle clogging problems.**

For the four follow-up units over the 4-month operating period, only minor shifts were noted in CO and NO_x. Smoke increased by 90 percent, HC increased by 200 percent, and filterable and total particulate increased by 131 and 76 percent, respectively. However, if the data from Unit 25 are omitted, the average particulate emissions do not increase over the 4-month period. The increase in HC emissions was primarily associated with Units 24 and 25. As stated earlier, Unit 25 had unusual problems, which were responsible for increased emissions from that unit. The increase in HC emissions between the 1st and 2nd follow-up visits for Unit 24 has not been explained.

Examination of the operating and emissions data for the two units that were included in both the Phase I and II studies showed that these units performed about the same for both years. Unit 12-24 had a tendency to have somewhat high CO and HC emissions; this was evident on each visit.

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*Flame retention head.

**See explanation in Table II-19.

Table II-16. Summary of Emissions and Emission Factors for Cyclic Runs on Follow-Up Units

Unit and Condition[a]		Operational Data: CO₂, %	O₂, %	Excess Air, %	Smoke No. at 9 Min[b]	Stack Temperature, F	Firing Rate, gph	Emission Data, Dose Average, ppm: CO	HC	NO	NOₓ	Particulate Loading, mg/sm³ [c]: Filterable	Total	Emission Factors, lb/1000 gal: CO	HC	NOₓ (as NO₂)	Particulate[c]: Filterable	Total
23	A	9.2	9.1	68	0.3	470	1.20	3.7	8.3	67	85	10.7	20.5	0.61	0.79	23.1	1.55	2.94
	T	9.9	7.8	54	0.5	480	–	7.7	5.7	82	89	7.2	26.0	1.17	0.50	22.2	0.93	3.44
	R	9.4	8.2	60	0.4	480	1.30	2.6	3.2	75	79	6.4	20.5	0.41	0.29	20.5	0.88	2.82
23.1	T	8.8	9.1	72	0.1	–	–	7.0	6.8	86	84	–	–	1.20	0.67	24.3	–	–
	R	8.4	9.3	77	0.1	–	1.28	8.7	7.7	76	77	–	–	1.51	0.77	22.0	–	–
23.2	T	8.7	9.0	73	0.0	435	–	4.5	8.3	85	85	–	–	0.78	0.82	24.1	–	–
	R	8.8	8.8	70	0.0	445	1.30	2.9	4.6	91	97	12.6	24.8	0.48	0.46	26.6	1.82	3.59
12[d]	A	7.4	10.3	97	3.0	590	0.96	66.4	9.4	–	69	10.4	33.2	10.96	1.05	22.4	1.74	5.67
	T	7.2	10.5	102	1.0	600	0.98	76.9	5.5	–	78	7.0	16.9	13.37	0.63	25.5	1.23	2.98
	R	6.7	10.8	111	1.0	–	–	76.1	11.7	–	62	–	–	13.90	1.39	21.5	–	–
24[d]	A	7.1	12.0	120	0.4	645	1.04	222.0	12.2	39	78	6.1	15.4	48.28	1.52	27.9	1.17	2.93
	T	**8.9**	9.0	71	0.7	520	–	4.1	3.1	71	76	19.0	47.6	0.69	0.30	21.1	2.82	7.02
	R	**9.2**	8.5	64	0.8	520	0.86	9.5	4.5	69	71	18.8	32.2	1.53	0.42	18.8	2.64	4.53
24.1	T	**8.8**	9.0	72	0.2	–	–	20.1	5.3	59	60	–	–	3.38	0.51	16.6	–	–
	R	**9.0**	8.3	65	0.1	–	0.95	18.3	11.7	62	64	–	–	2.96	1.08	17.0	–	–
24.2	T	**7.8**	**10.5**	95	0.2	610	–	41.4	28.7	56	58	–	–	8.07	3.20	18.6	–	–
	R	**8.6**	9.2	74	0.7	605	1.02	10.9	21.0	64	64	8.8	26.6	3.41	2.06	18.0	1.31	4.27
25	A	**8.4**	**9.0**	75	1.0	490	1.35	10.6	5.4	42	56	5.7	25.0	1.83	0.53	15.9	0.83	3.73
	T	**9.4**	7.3	56	1.7	450	–	8.6	5.9	47	47	7.4	19.4	1.32	0.52	11.8	0.97	2.57
	R	8.5	**8.8**	72	2.0	455	1.40	12.1	5.7	44	49	7.9	17.7	2.05	0.55	13.7	1.16	2.61
25.1	T	10.8	6.6	42	0.4	–	–	15.5	8.6	49	47	–	–	2.17	0.69	11.2	–	–
	R	10.9	6.5	41	0.1	–	1.38	14.7	5.9	54	48	–	–	2.03	0.47	12.3	–	–
25.2[e]	T	9.1	8.4	64	4.1	500	–	10.3	22.7	38	36	–	–	1.66	2.10	10.1	–	–
	R	10.1	7.0	49	5.8	485	1.59	11.8	22.0	37	39	78.9	100.5	1.72	1.84	9.4	9.99	12.69
16[f]	A	6.7	11.3	118	2.0	520	1.60	17.0	6.8	–	51	9.7	22.7	1.68	0.84	20.5	1.82	4.31
	T	6.9	11.1	112	1.5	–	1.75	17.1	6.7	–	60	–	–	1.62	0.80	20.4	–	–
	R	6.9	11.2	111	1.0	–	–	17.5	6.7	–	60	–	–	1.69	0.80	23.0	–	–
26[f]	A	7.1	11.1	109	0.5	520	1.78	5.5	5.1	54	64	11.1	33.2	1.13	0.60	21.6	1.96	5.97
	T	8.7	9.1	73	0.4	500	–	6.0	4.0	68	71	9.1	17.6	1.02	0.39	19.9	1.35	2.61
	R	8.8	8.8	70	0.5	490	1.80	10.7	4.4	67	72	10.7	21.4	1.78	0.42	19.7	1.55	3.11
26.1	T	9.4	8.2	62	0.2	–	–	6.9	6.8	69	74	–	–	1.09	0.62	19.2	–	–
	R	9.4	8.0	59	0.2		1.79	7.0	6.1	69	73	–	–	1.10	0.55	18.8	–	–
26.2	T	9.2	8.2	62	0.5	510	–	5.5	7.8	66	68	–	–	0.88	0.71	17.8	–	–
	R	9.0	8.6	66	0.4	510	1.80	5.2	7.2	66	67	9.1	18.2	0.85	0.67	18.0	1.29	2.58

[a] Decimals (.1 and .2) refer to 1st and 2nd follow-up visits.

[b] Smoke data for Units 12 and 16 are obtained at the 5-minute point.

[c] Modified EPA procedure.

[d] Unit 12 from Phase I and Unit 24 from Phase II were the same unit.

[e] Unit 25 was adjusted between measurements due to the nozzle clogging problem described in Table II-19.

[f] Unit 16 from Phase I and Unit 26 from Phase II were the same unit.

Table II-17. Average Emissions for Follow-Up Units

Units	Condition	Bacharach Smoke Number, 9th minute	Mean Emission Factors, lb/1000 gal				
			Gaseous Emissions			Particulate Emissions[a]	
			CO	HC	NO_x (or NO_2)	Filterable	Total
Four Follow-up Units (Units 23, 24, 25, & 26)							
Initial Visit	A	0.6	13.0	0.86	22.1	1.38	3.89
	T	0.8	1.05	0.43	18.8	1.52	3.91
	R	0.9	1.44	0.42	18.2	1.56	3.27
1st Follow-up	T	0.2	1.96	0.62	17.8	–	–
	R	0.1	1.90	0.72	17.5	–	–
2nd Follow-up	T	1.2	2.85	1.71	17.7	–	–
	R	1.7	1.62	1.26	18.0	3.60	5.78
Three Follow-Up Units (Units 23, 24, & 26)							
Initial Visit	A	0.4	16.7	0.97	24.2	1.56	3.95
	T	0.5	0.96	0.40	21.1	1.70	4.36
	R	0.6	1.24	0.38	19.7	1.69	3.49
1st Follow-up	T	0.2	1.89	0.60	20.0	–	–
	R	0.1	1.86	0.80	19.3	–	–
2nd Follow-up	T	0.2	3.24	1.58	20.2	–	–
	R	0.4	1.58	1.06	20.9	1.47	3.48
Emission Ratios Based on Four Units (Units 23, 24, 25, & 26)							
$\frac{\text{1st Follow-up}}{\text{Initial Visit}}$	R	0.1	1.32	1.71	0.96	–	–
$\frac{\text{2nd Follow-up}}{\text{Initial Visit}}$	R	1.9	1.13	3.00	0.99	2.31	1.76
Emission Ratios Based on Three Units (Units 23, 24, & 26)							
$\frac{\text{1st Follow-up}}{\text{Initial Visit}}$	R	0.2	1.50	2.11	0.98	–	–
$\frac{\text{2nd Follow-up}}{\text{Initial Visit}}$	R	0.7	1.27	2.79	1.06	0.87	1.00

[a] Modified EPA procedure.

The general lack of any large increase in emissions for Units 23, 24, and 26 during the Phase II study supports the finding reported earlier that tuning of units that are generally performing satisfactorily does not result in a large reduction in emissions. However, periodic servicing should identify problems such as those experienced by Unit 25 and permit correction of these problems. The high smoke level measured during the last visit to this unit would identify existence of a problem, using equipment and techniques presently available to burner servicemen.

The incremental changes in efficiency of the follow-up units between the first and last visits were as follow:

Unit 23	+ 0.4 percent
Unit 24	– 2.8 percent
Unit 25	+ 0.1 percent
Unit 26	+ 0.5 percent.

Hence, except for Unit 24, the incremental change in efficiency was insignificant. The incremental increase in efficiency upon tuning during the initial visit for Unit 24 was 8.8 percent. Apparently, during the 4-month interval between the initial visit (and tuning) and the last visit, performance of this unit had begun to deteriorate. However, its performance (efficiency) was still superior to that in the as-found condition.

Table II-18 and II-19 provide information on the operating cycles and service history of the units during the follow-up period. Degree-days during the approximate 4-month period was 4100, indicating an average outdoor temperature of 34 F. Table II-18 shows that the load factor of the four units was remarkably similar, ranging from 30 to 38 percent on time (compared with 33 percent chosen for the cyclic runs). The average cycles per hour ranged from 1.2 to 4.7 for the four units (compared with 2 cycles per hour for the cyclic runs). The steam boiler operated with longer cycles characteristic of this type of unit.

Experiments on the Effect of Cycle

A series of experiments were made to investigate the effect of cycle with Unit 35, which was operated in the laboratory at Battelle-Columbus. This is a forced-air furnace unit with a high-pressure gun burner a conventional combustion head, and a ceramic felt combustion-chamber liner. Gaseous emissions were measured while the unit was operated in the following cycles:

Min. On/Min. Off	Cycles/Hour	Percent Time On
Equilibrium	–	100
10/20*	2	33
10/5	4	67
7.5/7.5	4	50
5/10*	4	33
1.5/13.5	4	10
6.7/3.3	6	67
3.3/6.7	6	33
1/9	6	10

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*Runs made with and without a solenoid oil valve.

Table II-18. Operational Data on Follow-Up Units

Unit (System Type)	Dates Month Day	Burner Operation Hours	Burner Operation Cycles	Average On Time, min[a]	Average Percent On Time[a]	Average Cycles per Hour[a]
23	12-10 - 1-10	221	–	–	30	–
(Water)	1-10 - 2-16	306	4644	4.0	34	5.2
	2-16 - 4-26	462	7521	3.7	28	4.5
	1-10 - 4-26	768	12127	3.8	30	4.7
24	12-13 - 1-10	234	–	–	35	–
(Warm Air)	1-10 - 1-17	68	330	12.3	40	2.0
	1-17 - 1-22	41	276	9.0	34	2.3
	1-22 - 1-26	22	165	8.1	31	2.3
	1-25 - 1-29	45	240	11.3	47	2.5
	1-29 - 2-4	59	353	10.0	41	2.5
	2-4 - 2-9	72	289	15.0	60	2.4
	2-9 - 2-15	64	377	10.1	44	2.6
	2-15 - 2-21	66	334	11.8	46	2.3
	2-21 - 2-26	64	306	12.6	53	2.6
	2-26 - 3-10	122	692	10.5	39	2.2
	3-10 - 3-18	76	459	9.9	40	2.4
	3-18 - 3-26	75	460	9.7	39	2.4
	3-26 - 4-9	116	757	9.2	35	2.3
	4-9 - 4-16	39	294	8.0	23	1.8
	4-16 - 4-25	38	292	7.9	18	1.4
	1-10 - 4-25	965	5624	10.3	38	2.2
25	12-16 - 1-10	175	–	–	29	–
(Water)	1-10 - 1-17	52	644	4.8	31	3.8
	1-17 - 1-22	34	437	4.7	28	3.6
	1-22 - 1-31	66	803	4.9	31	3.7
	1-31 - 2-15	139	1555	5.4	39	4.3
	2-15 - 3-3	136	1600	5.1	33	3.9
	3-3 - 3-10	62	668	5.6	37	4.0
	3-10 - 3-24	109	1233	5.3	32	3.7
	3-24 - 4-15	144	1915	4.5	27	3.6
	4-15 - 4-24	36	571	3.8	17	2.6
	1-10 - 4-24	778	9426	5.0	31	3.7
26	12-18 - 12-16	72	–	–	38	–
(Steam)	12-26 - 1-2	55	–	–	33	–
	1-2 - 1-10	84	–	–	44	–
	1-10 - 1-14	22	138	9.6	23	1.4
	1-14 - 1-24	105	322	19.5	44	1.3
	1-24 - 1-30	60	152	23.6	42	1.1
	1-30 - 2-5	72	152	28.3	50	1.1
	2-5 - 2-11	78	166	28.3	54	1.2
	2-11 - 2-14	22	87	15.1	31	1.2
	2-14 - 2-24	108	279	23.1	45	1.2
	2-24 - 3-11	127	479	15.9	33	1.2
	3-11 - 3-18	57	154	22.2	34	0.9
	3-18 - 3-25	57	182	18.8	34	1.1
	3-25 - 4-10	123	433	17.1	32	1.1
	4-10 - 4-22	50	356	8.5	17	1.2
	4-22 - 4-27	20	156	7.8	17	1.3
	1-10 - 4-27	901	3056	17.7	35	1.2

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[a] Cycle used in measurements was: On Time, min = 10
Percent On Time = 33
Cycles per Hour = 2.0

Table II-19. History of Follow-Up Units Between Visits

Unit 23.	No servicing or adjustments of any kind were made on this unit between visits.
Unit 24.	On February 4, 1972, a no-heat service call was made to this unit. The serviceman diagnosed the trouble as a burned out burner motor, which was replaced without making any other adjustments to the unit.
Unit 25.	A new shipment of oil (376 gal) was delivered to this unit on January 26, 1972. Because of prior problems associated with oil deliveries, the burner on this unit is normally turned off and the oil company has specific instructions for a slow-fill. On the date in question no one was home and a new driver, not having been duly informed, fast-filled the tank. The fast-fill stirred up sediment in the tank and clogged the nozzle, causing shutdown; the home owner cleaned the nozzle and adjusted the air to achieve good combustion. Additional problems were encountered with this unit on February 16, 1972. Following the conclusion of the series of emission measurements on the first follow-up visit, the burner would not ignite. The trouble was diagnosed as a clogged filter and a partially blocked fuel line. The old filter was replaced and the fuel line from the filter to the tank was blown out with CO_2 cartridges. This corrected the problem and the unit was set to the same CO_2 as for the tuned condition of the initial visit and was left on this setting.
Unit 26.	No servicing or adjustments of any kind were made on this unit between visits.

Table II-20 shows the emissions measured by the procedure used for the cyclic runs in the field, plus equilibrium operation for comparison. As might be expected from combustion temperature considerations, runs with shorter "on" time generally yielded slightly higher CO and HC and lower NO_x. (Particulates were not measured during these runs.) Improved cutoff at shutdown with the addition of a solenoid oil valve resulted in slightly lower HC emissions where comparable cycles were run with and without the solenoid.

The temperature of the lightweight, highly insulating combustion-chamber liner in this unit would be expected to respond rapidly to transient operations. A unit with a dense, highly conductive refractory liner would be expected to have a slow response and, thus, to show larger cyclic effects on emissions.

Table II-20. Effect of Cycle on Emissions

Cycle		Operating Conditions[a]				Dose Average Emissions Data, ppm			
"On", min/"Off", min	Percent On Time	CO_2[b], %	O_2[b], %	Stack Temperature Just Before Shutoff	Solenoid in Use	CO	HC	NO	NO_x
Steady state (2 hr)	100	10.3	6.8	488	–	11.0	4.0	77	76.5
10/20	33	10.1	7.3	481	No	13.3	15.3	72	71
10/20	*33*	*10.1*	*7.2*	*486*	*Yes*	*13.3*	*14.8*	*73*	*74*
10/5	67	10.3	6.9	478	No	13.6	9.8	77	76
7.5/7.5	50	10.3	6.9	470	No	13.8	11.7	79	78
5/10	33	10.2	7.0	441	No	14.5	11.7	76	76
5/10	*33*	*10.3*	*7.1*	*448*	*Yes*	*14.4*	*9.9*	*74*	*74*
1.5/13.5	10	10.1[c]	7.5[c]	323	No	16.8	18.7	70.5[c]	74.5
6.7/3.3	67	10.3	6.7	467	No	13.6	8.8	76	76.5
3.3/6.7	33	10.2	7.0	405	No	15.0	13.5	74	74
1/9	10	9.6[c]	8.4[c]	245	No	17.0	26.7	66[c]	66.5[c]

[a] All smoke readings (made 1 minute after lightoff and just before shutdown) were 0.4 or less on the Bacharach scale.

[b] Average values over "on" period.

[c] Values recorded at end of "on" cycle, as the on-time was too short to obtain meaningful average values.

EMISSION RESULTS FOR VARIED-AIR RUNS

The purpose of the varied-air runs was to characterize the sensitivity of emissions to air adjustment for the various residential units. These runs were made at steady-state conditions and the only adjustment made between points was to reposition the air gate.

This section contains a summary of gaseous emissions and smoke measurements for the varied-air runs on the residential units. Particulate emissions were not measured for the varied-air runs.

Appendix G of the Data Summary Volume contains tabulated emission data and plots of emissions versus excess air (in terms of CO_2 reading) for varied-air runs at all operating conditions (as-found, tuned, and reference-fuel runs). Appendix I reports the same data in terms of emission factors.

Emission Characteristics Related to Excess Air

Gaseous emissions and smoke were measured at about six steady-state conditions representing a range of excess air settings between the wide open setting of the air gate and a setting which gave a smoke level of 5 to 7. Plots of emissions versus excess air or CO_2 provide an indication of the operating range producing low gaseous emissions or smoke. Figure II-6 is an example plot showing the variation of smoke and gaseous emissions with CO_2 for one unit.

Figures II-7 through II-19 show summary curves of smoke, CO, and HC, for all 12 residential units – comparing as-found (A), tuned (T), and reference-fuel (R) conditions. NO_x was not highly sensitive to air setting and is not summarized in these curves. Individual data points are tabulated and plotted against CO_2 for each condition in the Data Supplement Volume.

Examination of Figures II-7 to II-19 show that each of these units is unique in its combustion characteristics. In fact, it is quite difficult to select any one of these units as having combustion characteristics which are typical of the group of units. Some units exhibited very sharp breaks in the smoke curves; others had broad, sweeping curves. Tuning generally improved the smoke curve (moved it toward higher CO_2 values), but, as tuning was primarily oriented toward reducing smoke, this was not surprising. Most units had very low CO and HC emissions over the normal range of operation in the as-found condition, so that significant improvement upon tuning was not possible.

The most significant point that can be made from these data is that smoke is a good indicator of low CO and HC emissions at high CO_2 levels but not at low CO_2 levels. That is, almost without exception, as excess air is gradually decreased from the normal operating range, the smoke level begins to increase sharply before the CO and HC emissions show significant increases. However, as excess air is increased, CO and HC emissions increase quite rapidly while smoke levels remain low. Hence, at high CO_2 levels low smoke is a fairly good indicator that a burner is adjusted for low CO and HC emission levels. Conversely, smoke is not a good measure of low CO and HC production in the low CO_2 range, and adjustment based on smoke alone could lead to high CO and HC emissions.

(Text continues on Page II-59.)

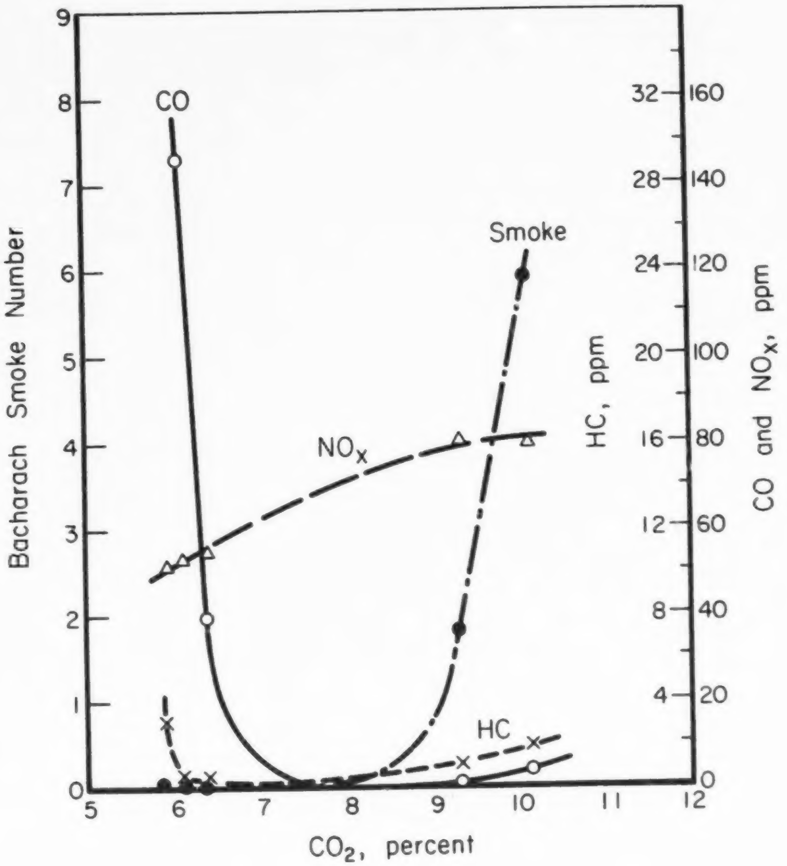

Figure II-6. **Typical Smoke and Gaseous Emission Characteristics for a Residential Unit**

Unit 24 in tuned condition firing house fuel.

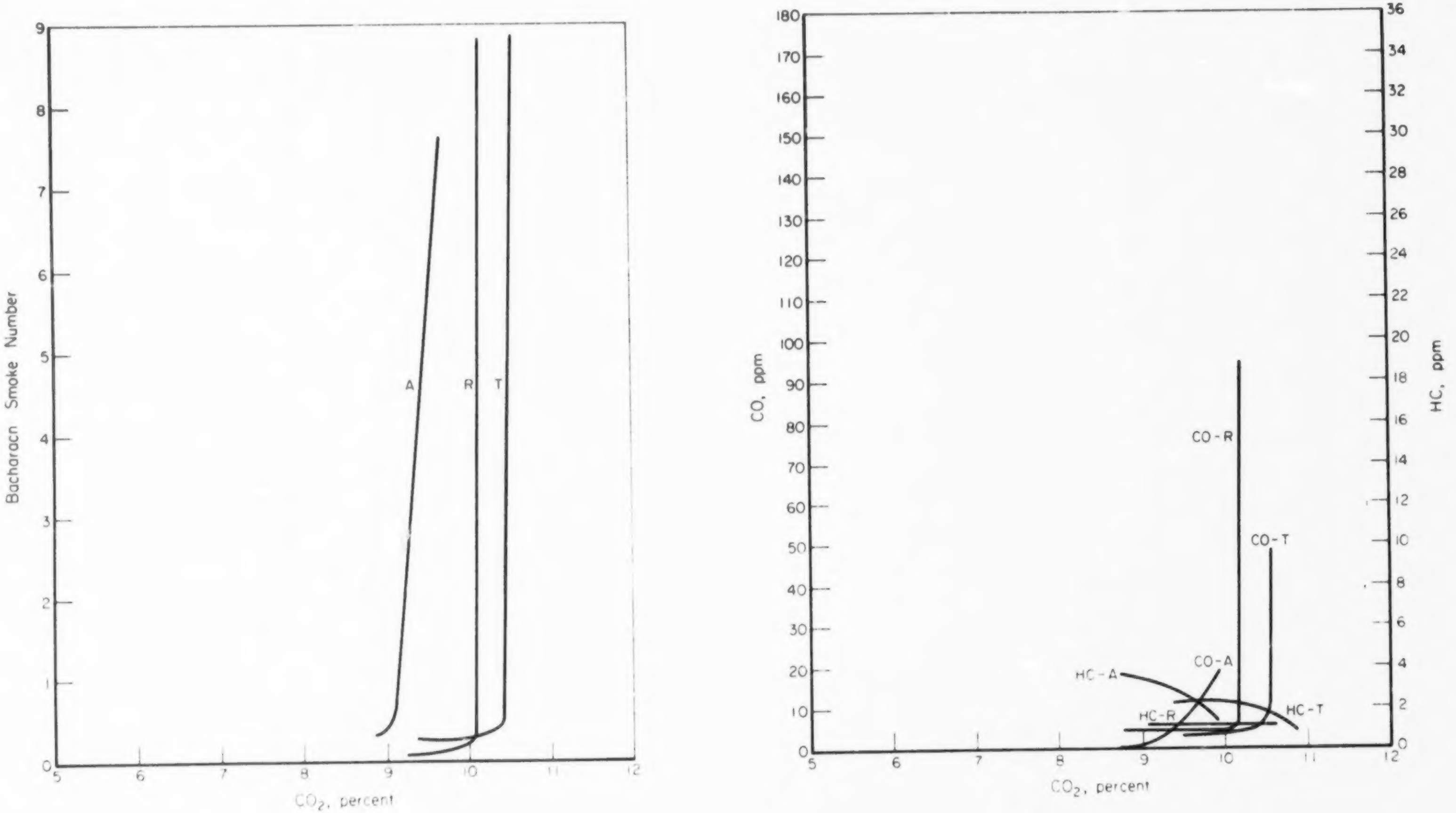

Figure II-7. Emissions for Residential Unit 23 as Function of CO_2

Lables on curves refer to pollutants (CO or HC) and/
or burner condition (A, T, or R).

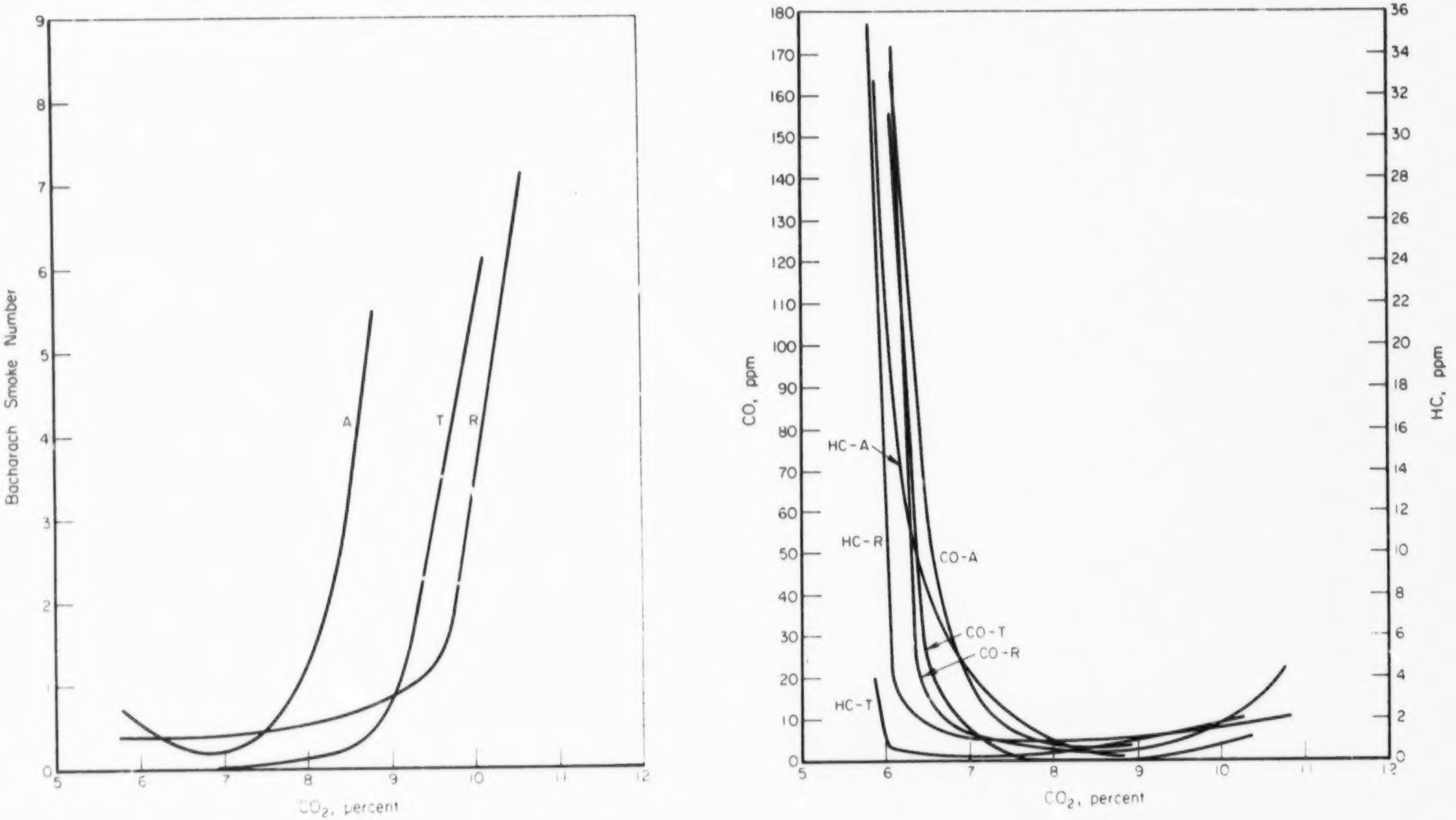

Figure II-8. Emissions for Residential Unit 24 as Function of CO_2

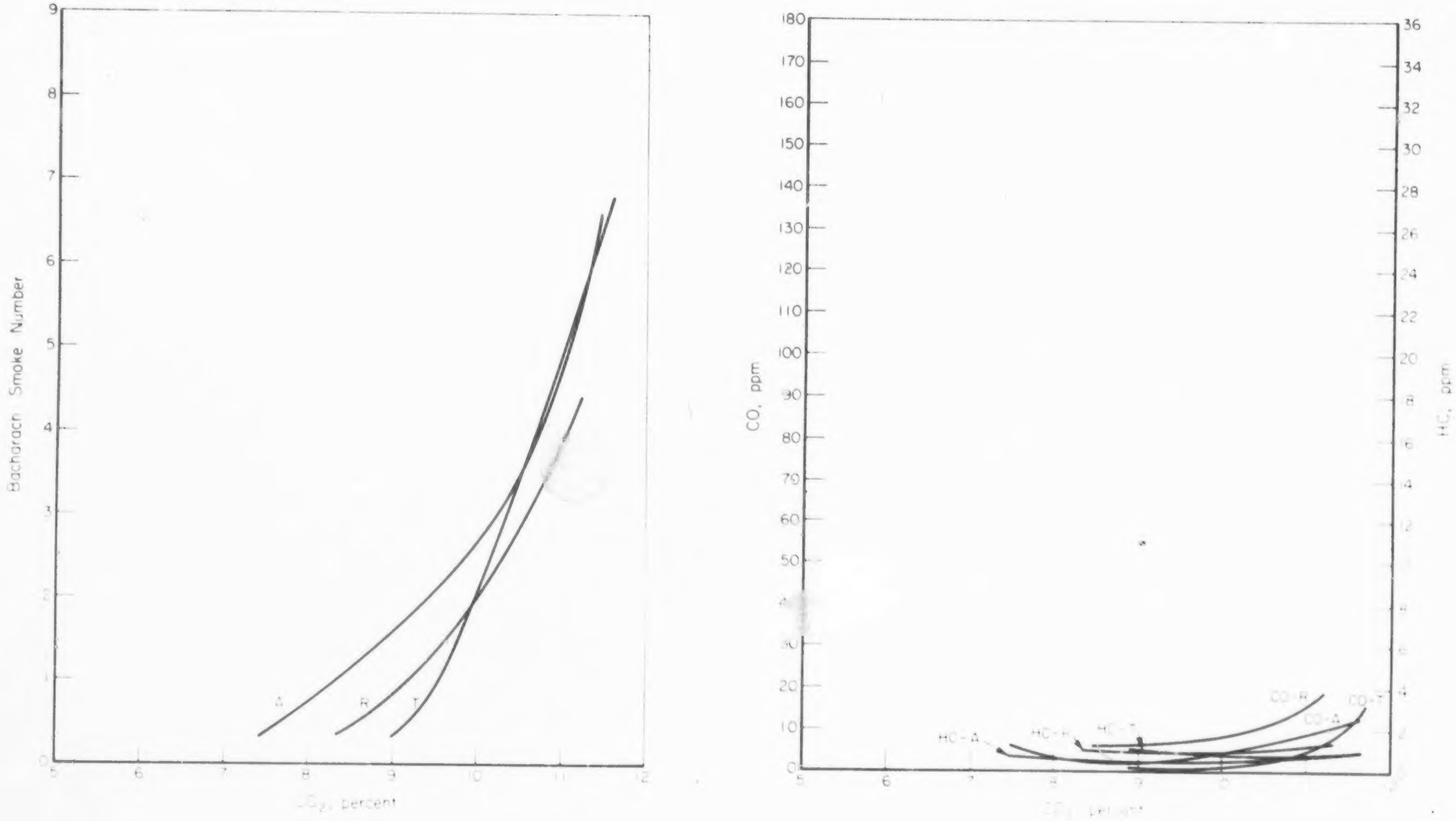

Figure II-9. Emissions for Residential Unit 25 as Function of CO_2

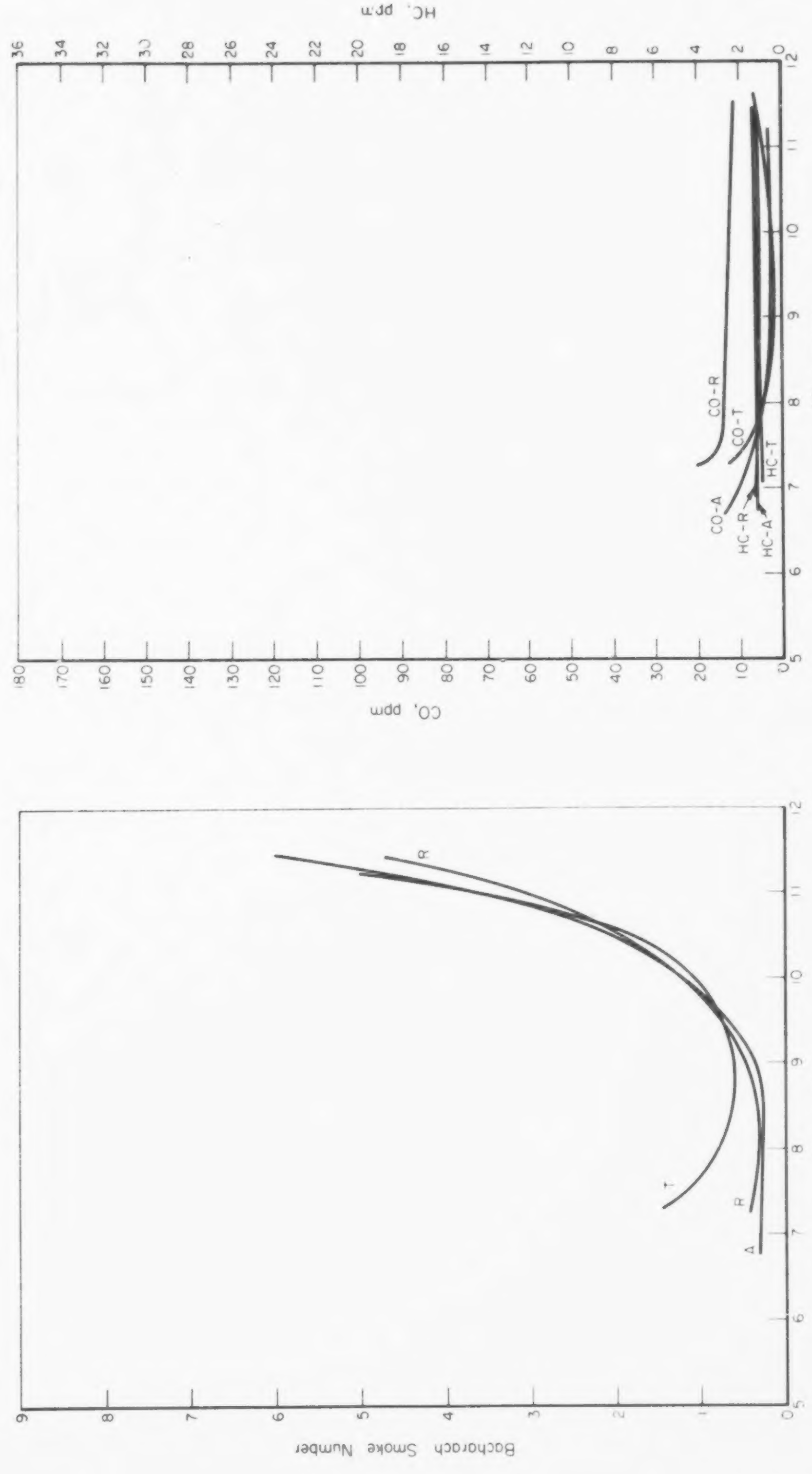

Figure II-10. Emissions for Residential Unit 26 as Function of CO_2

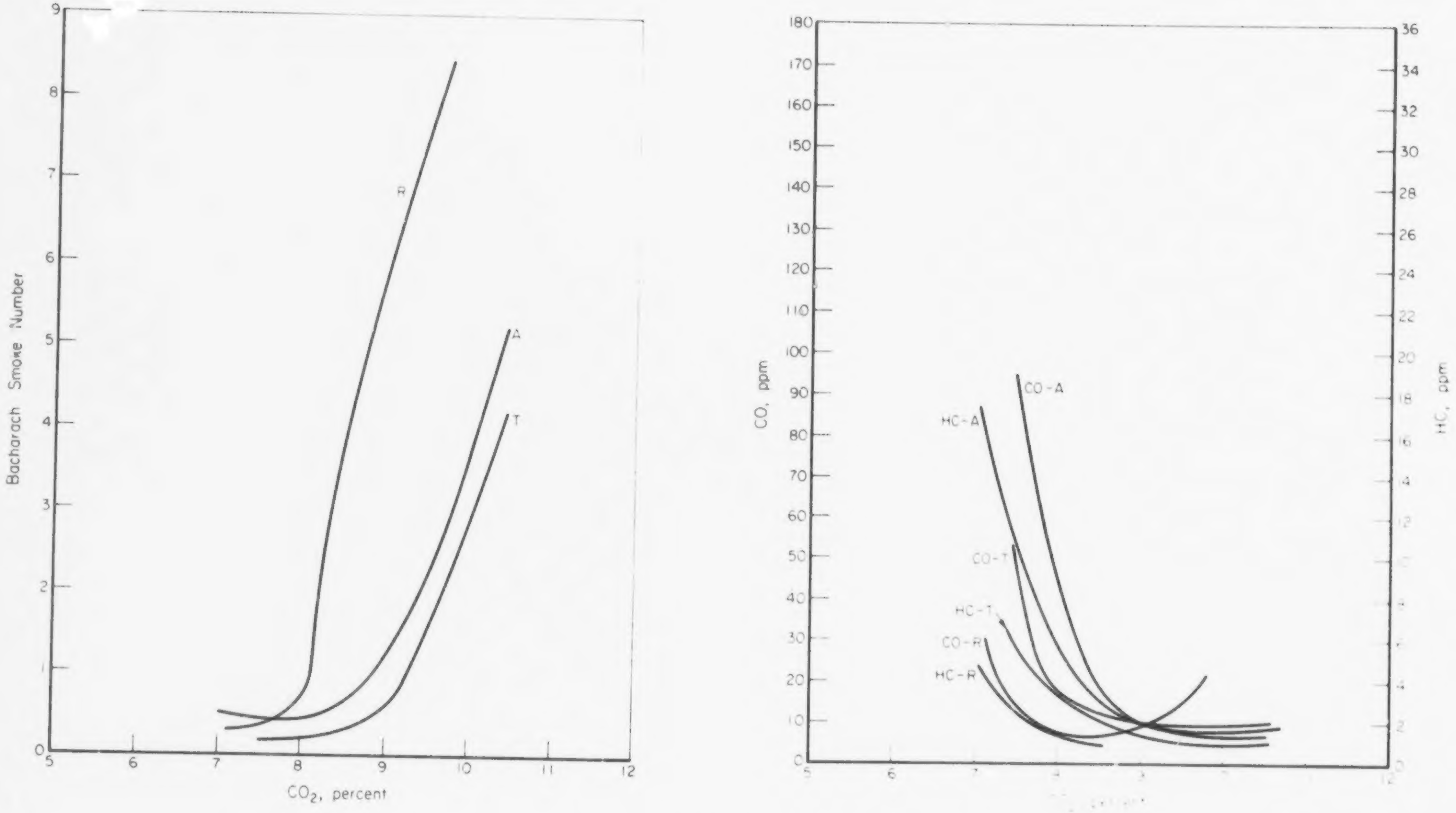

Figure II-11. Emissions for Residential Unit 27 as Function of CO_2

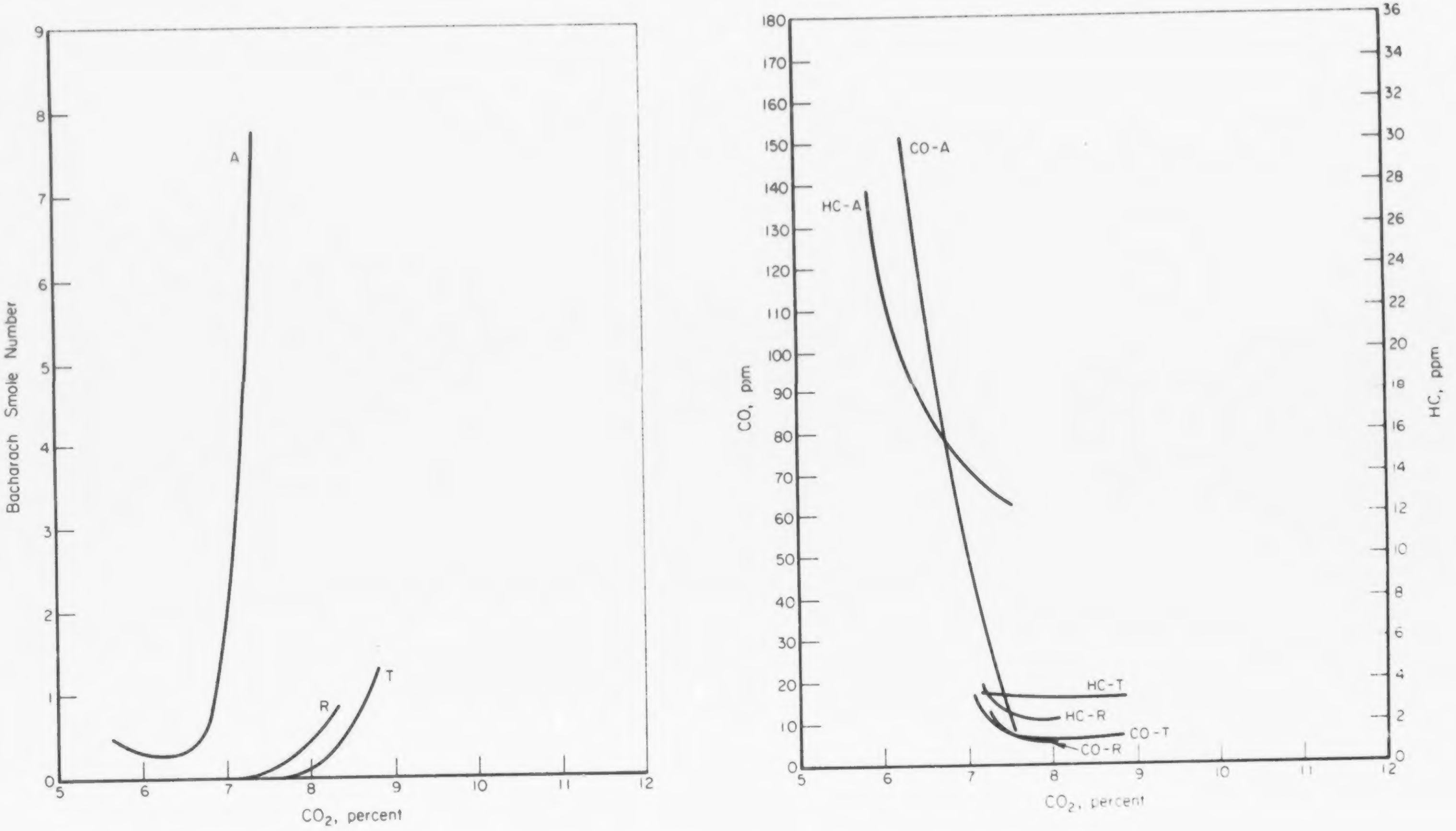

Figure II-12. Emissions for Residential Unit 28 as Function of CO_2

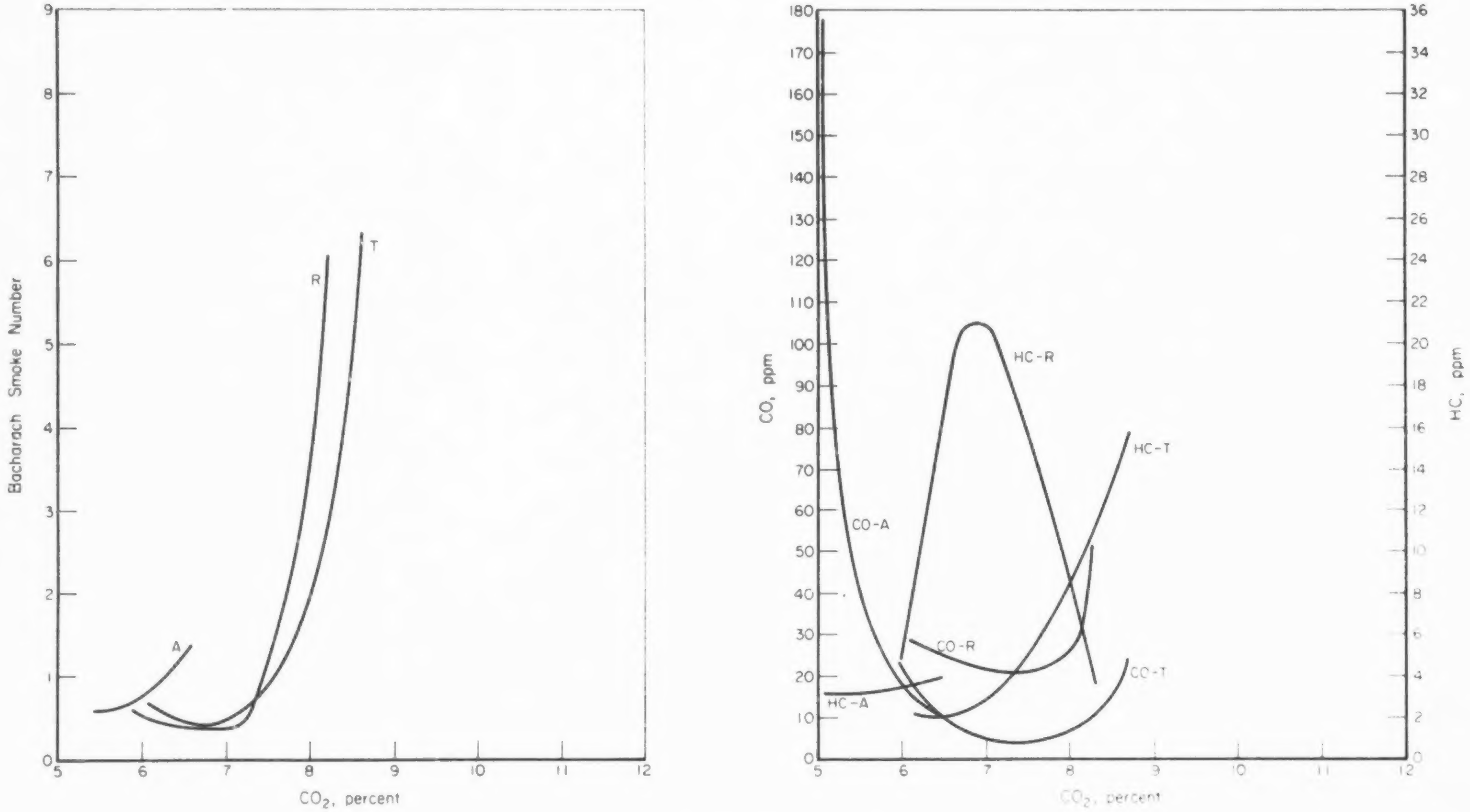

Figure II-13. Emissions for Residential Unit 29 as Function of CO_2

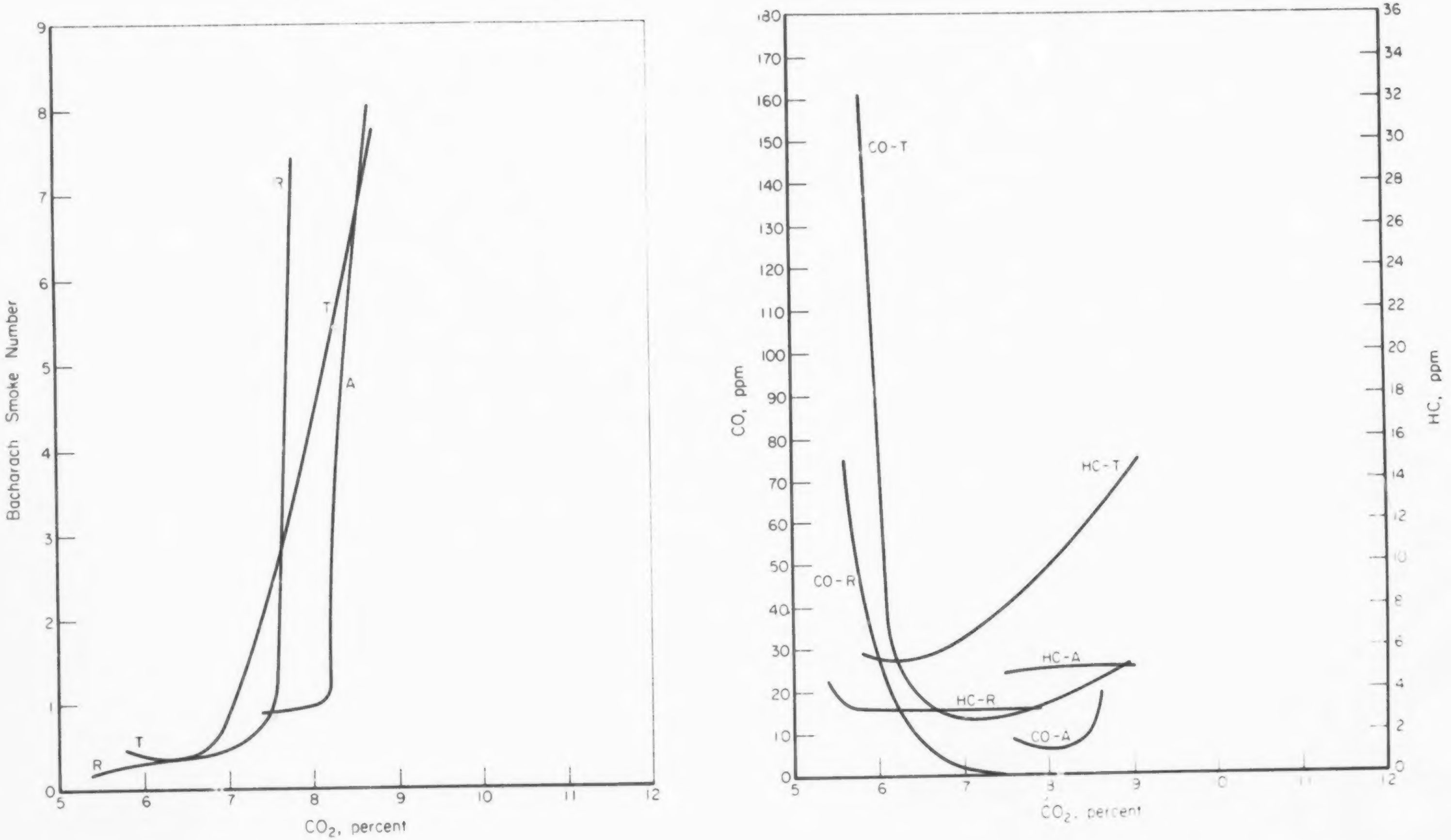

Figure II-14. Emissions for Residential Unit 30 as Function of CO_2

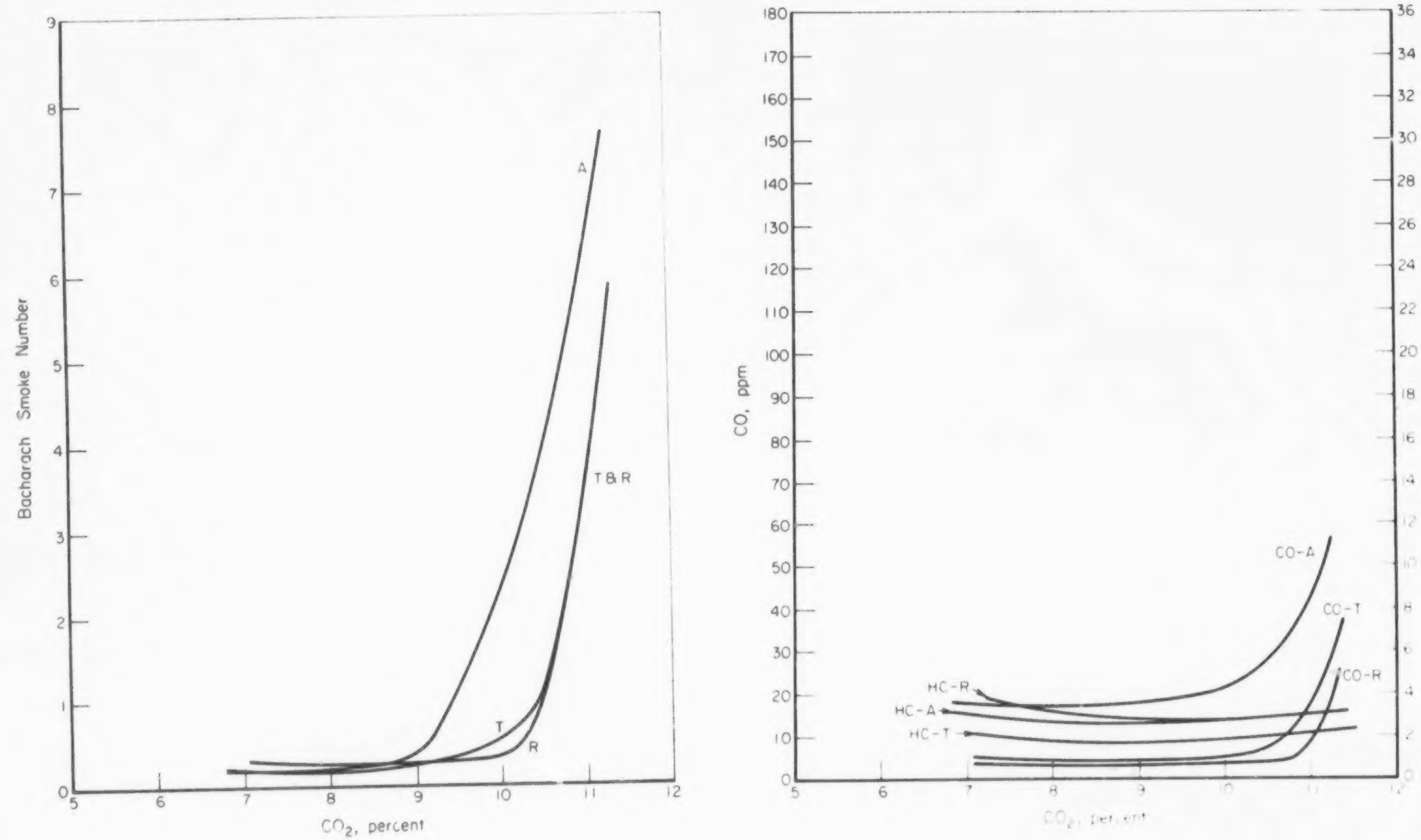

Figure II-15. Emissions for Residential Unit 31 as Function of CO_2

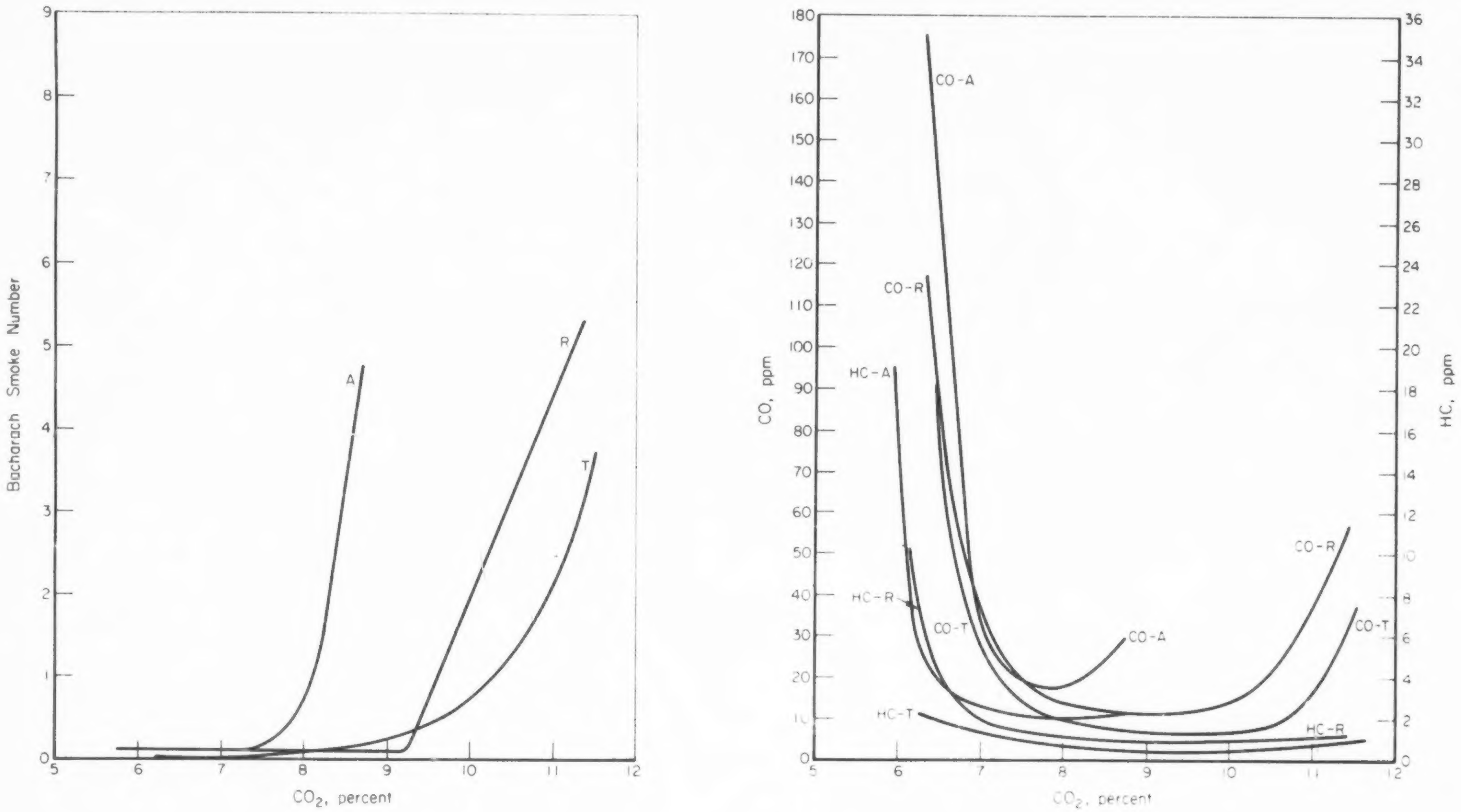

Figure II-16. Emissions for Residential Unit 32 as Function of CO_2

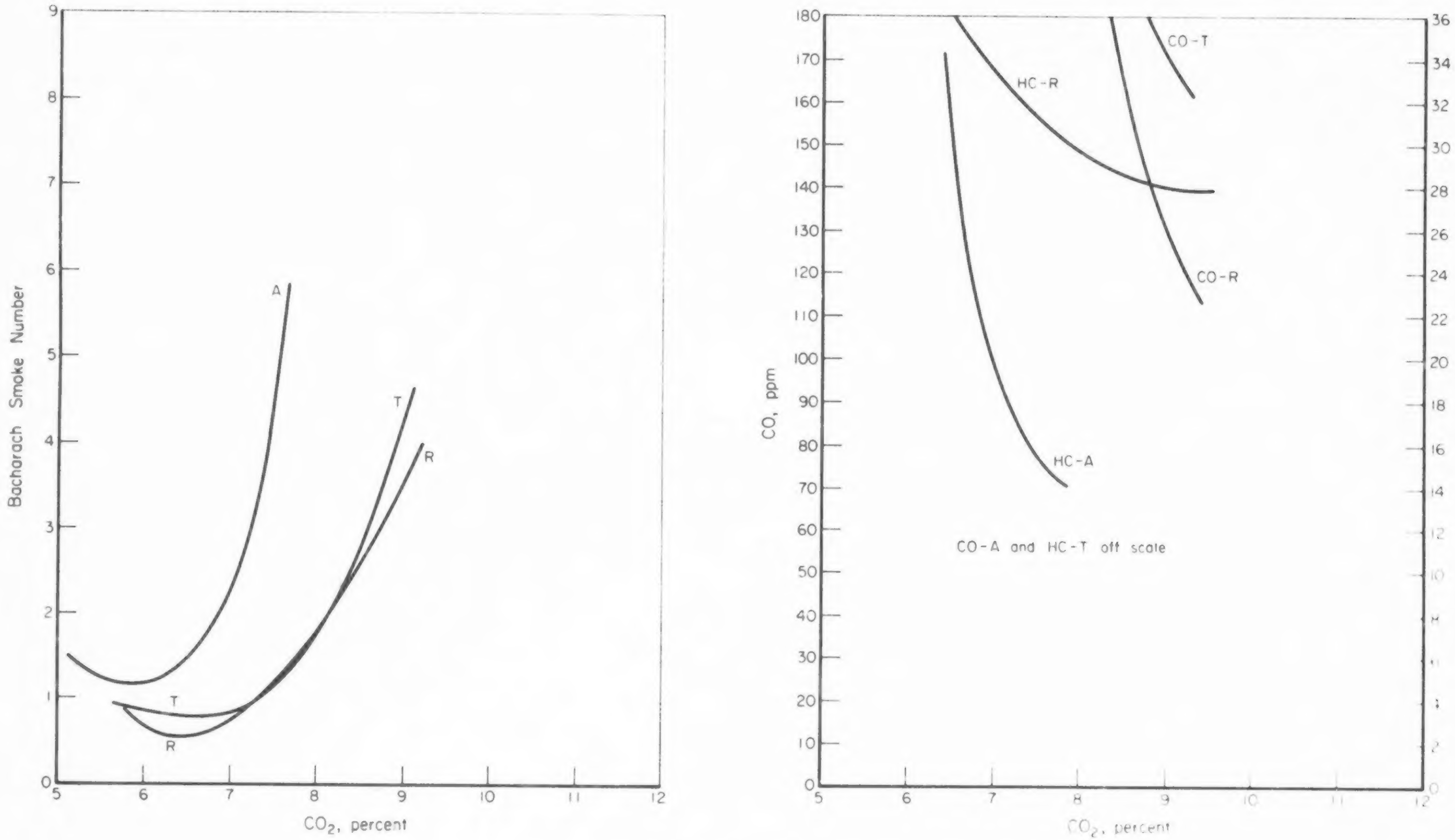

Figure II-17. Emissions for Residential Unit 33 as Function of CO_2

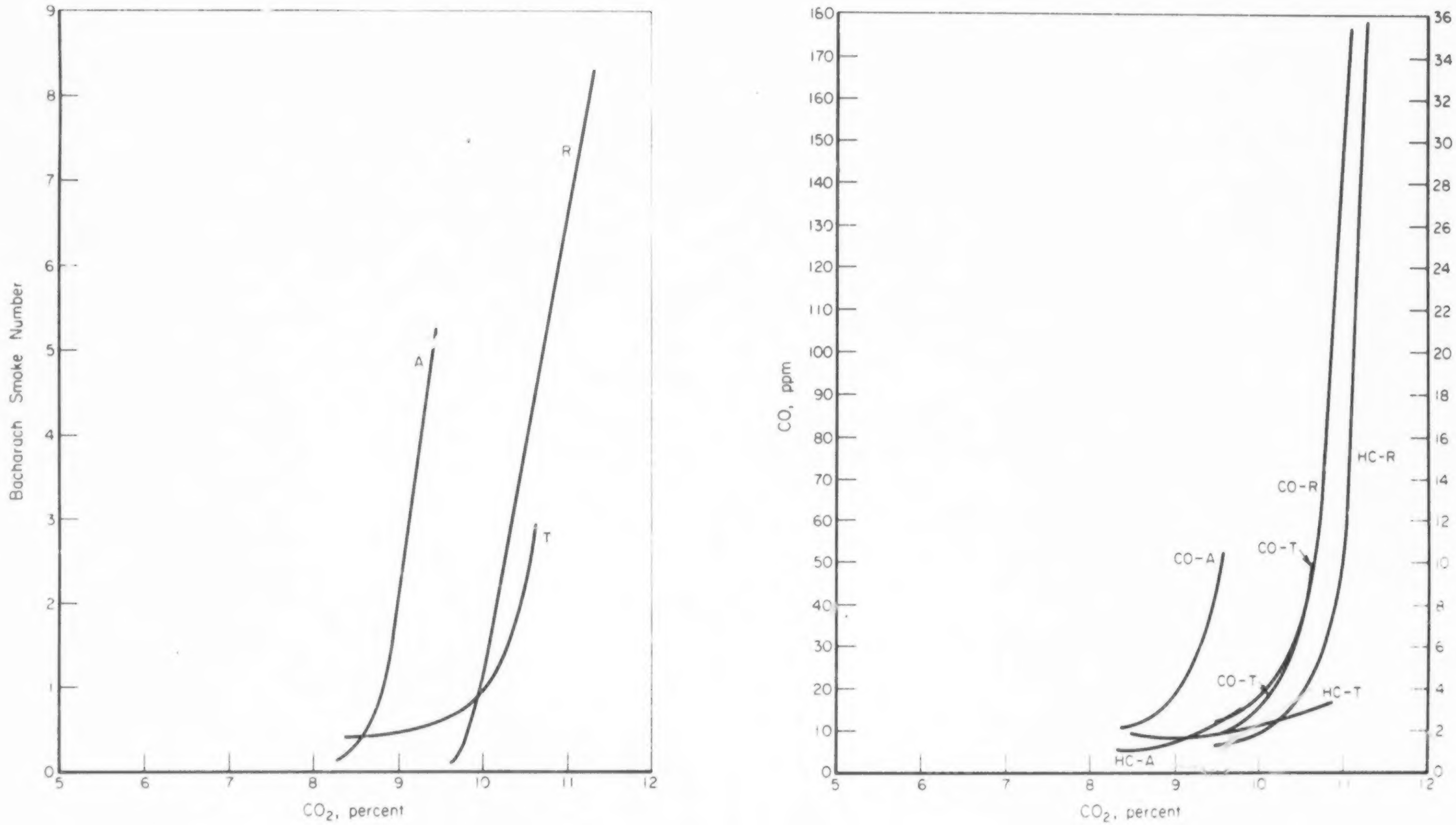

Figure II-18. Emissions for Residential Unit 34 as Function of CO_2

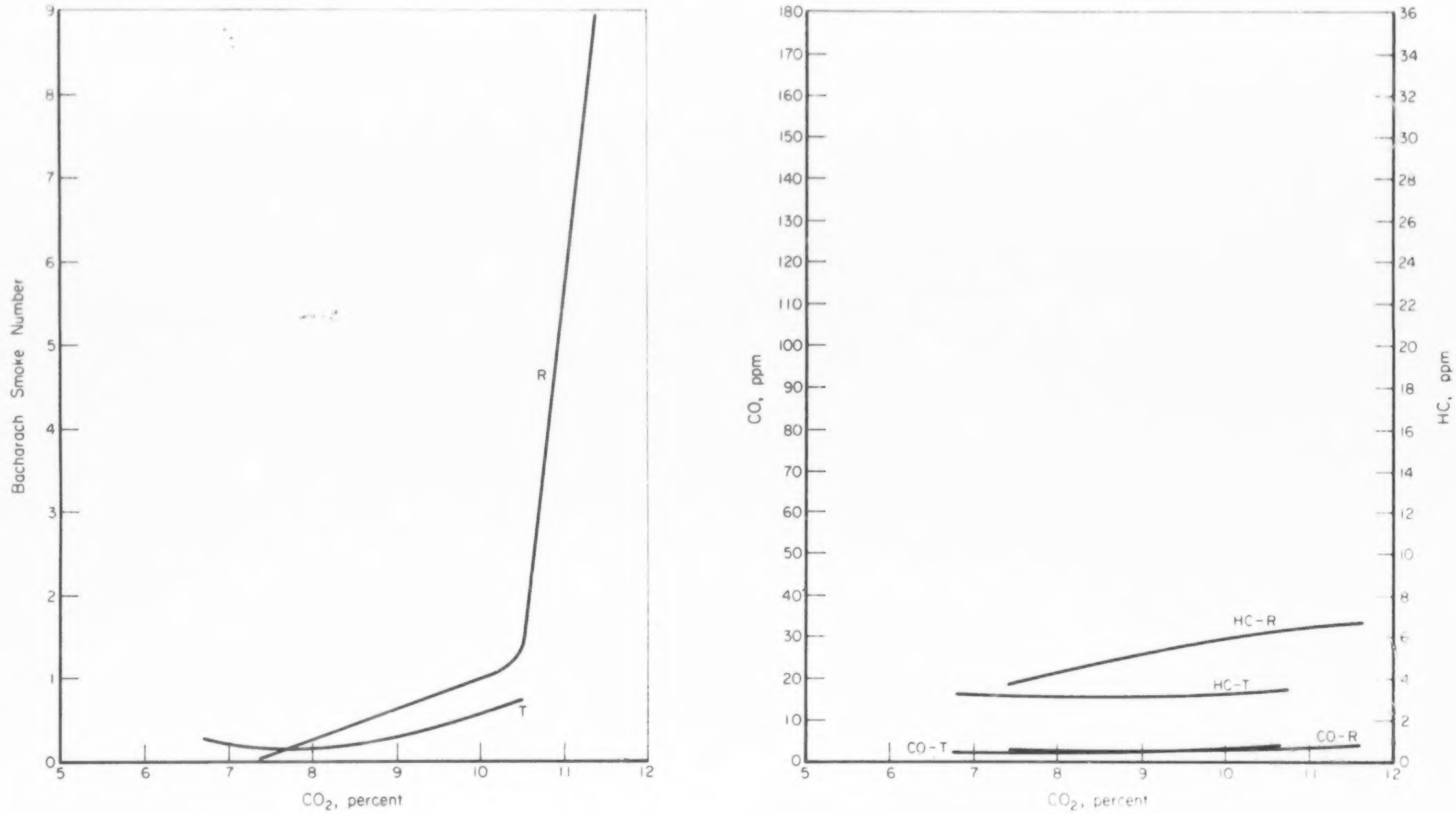

Figure II-19. Emissions for Residential Unit 35 as Function of CO_2

In view of these observations, the tuning procedure adopted for this program and used by many experienced servicemen for normal adjustments appears to be as good a means of achieving low overall emissions as can be devised using field instruments for smoke and CO_2 measurements. A knowledge of the smoke-versus-CO_2 curve for a particular burner permits adjusting the burner to a low smoke-high CO_2 level to both minimize emissions and operate efficiently.

Figure II-20 shows smoke versus CO_2 curves for all units in the as-found and tuned conditions, respectively. These figures further illustrate the wide range of combustion characteristics exhibited by the individual units.

For some burners, the adjustment limits for low-emission operation were very narrow. In several cases, the fan capacity limited the operating range such that CO_2 levels could not be set below 8 or 9 percent.

Limits of Acceptable Adjustment

Table II-21 shows a summary of the acceptable operating ranges for the various units, based on the following criteria without regard to CO, HC, or NO_x emissions:

- Minimum CO_2:8 percent (8 percent CO_2 was arbitrarily selected as the minimum CO_2 desired to achieve acceptable efficiency)
- Maximum CO_2:air adjustment for No. 2 smoke.

The acceptable operating range by these criteria averaged 1.26 percent CO_2 and exceeded 3 percent in two cases, but many units yielded negative values, which indicated that No. 2 smoke was exceeded at 8.0 percent CO_2.

TRIAL CORRELATIONS OF SMOKE VERSUS PARTICULATE

In the Phase I program, the possible correlation of steady-state Bacharach smoke numbers with cyclic particulate emissions was investigated, but no direct relationship was found.* The Phase II residential data exhibit the same lack of correlation, as will be seen by several plots.

Figures II-21 and II-22 show the attempted smoke versus particulate emission correlation for all Phase I and II data combined. No relation was found, considering either filterable or total particulate.

Figures II-23 and II-24 show the effect of tuning on the smoke-particulate relationship for Phase II units. A consistent slope of the connecting lines for the different units would suggest characteristic curves for individual burners, but even this relation was not observed.

One explanation for the lack of correlation between smoke (at 5 or 9 minutes) and particulate (integrated over the cycle) may be the particulate associated with start-up. Although data are not available to determine the contribution of particulate generated during start-up to

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*Limited Phase I data indicated a correlation between the carbon content of the particulate filter catch and smoke up to about No. 7 smoke, where the smoke spot apparently became "overloaded".

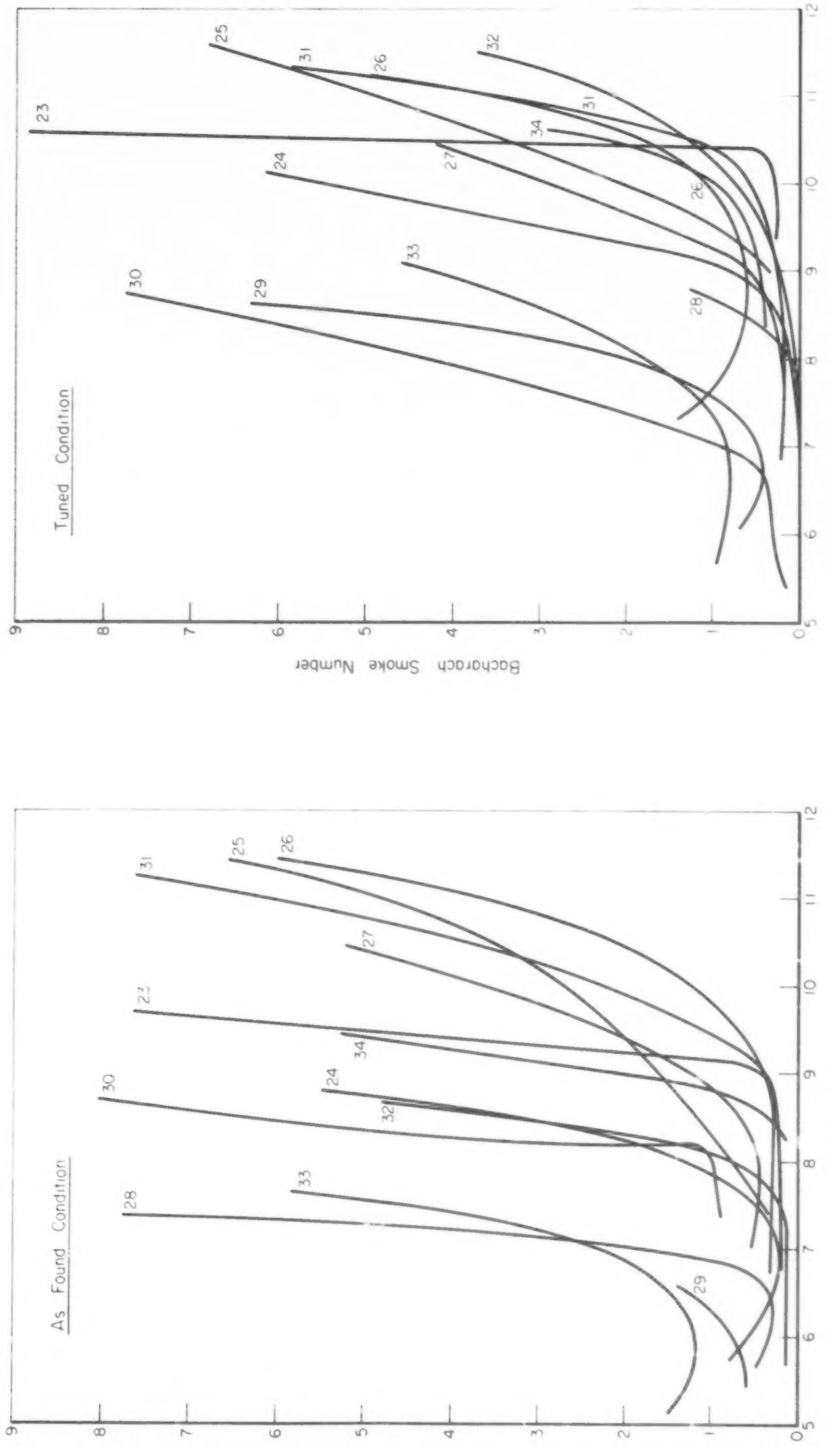

Figure II-20. Emissions for Residential Units Firing House Fuels

Table II-21. Evaluation of Unit Performance

Unit	Condition	CO_2 Level at Which No. 2 Smoke Occurs, %	Acceptable Range of Operation, % CO_2[a]
23	A	9.2	1.2
	T	10.5	2.5
	R	10.1	2.1
24	A	8.3	0.3
	T	9.3	1.3
	R	9.8	1.8
25	A	9.4	1.4
	T	10.0	2.0
	R	10.0	2.0
26	A	10.5	2.5
	T	10.6	2.6
	R	10.5	2.5
27	A	9.4	1.4
	T	9.7	1.7
	R	8.2	0.2
28	A	7.0	None
	T	9.1	1.1
	R	9.0	1.0
29	A	6.9	None
	T	8.0	0.0
	R	7.7	None
30	A	8.2	0.2
	T	7.4	None
	R	7.6	None
31	A	9.9	1.9
	T	10.7	2.7
	R	10.7	2.7
32	A	8.3	0.3
	T	11.0	3.0
	R	10.1	2.1
33[b]	A	6.9	None
	T	8.2	0.2
	R	8.2	0.2
34	A	9.0	1.0
	T	10.5	2.5
	R	10.2	2.2
35	T	11.1	3.1
	R	10.6	2.6
Average	A	–	0.85
	T	–	1.75
	R	–	1.50
All	All	–	1.26

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[a] Acceptable Range of Operation = CO_2 at which No. 2 smoke occurs -8.0.

[b] All smoke spots from this unit appeared to include raw fuel.

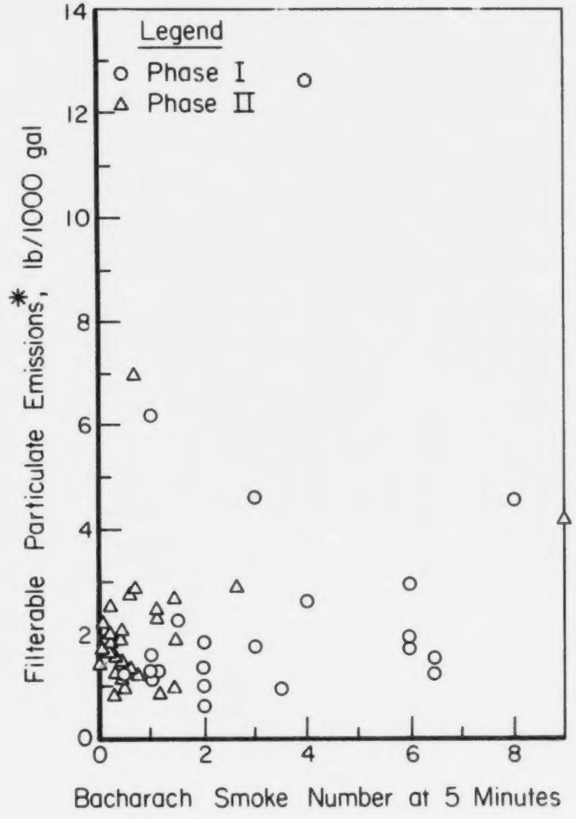

Figure II-21. Relation of Smoke Number and Filterable Particulate Emissions – Phase I and II Residential Data

*Modified EPA Procedure.

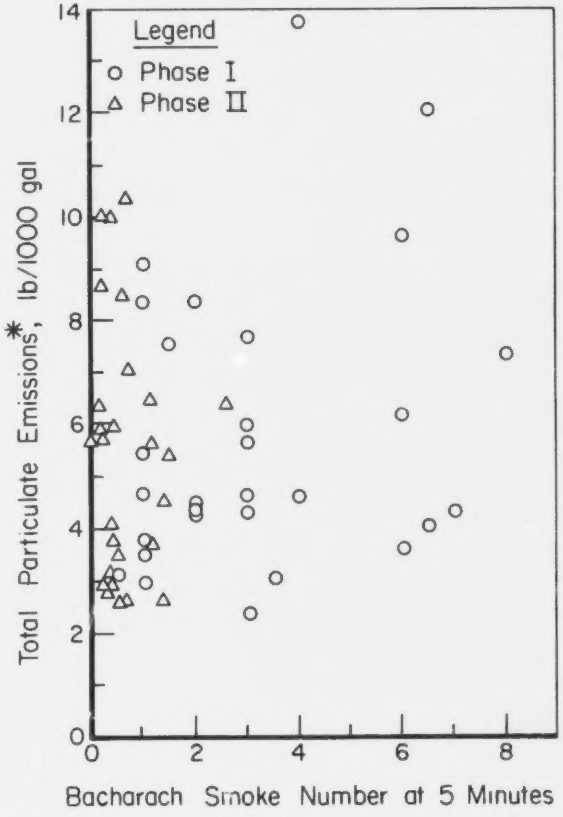

Figure II-22. Relation of Smoke Number and Total Particulate Emissions – Phase I and II Residential Data

*Modified EPA Procedure.

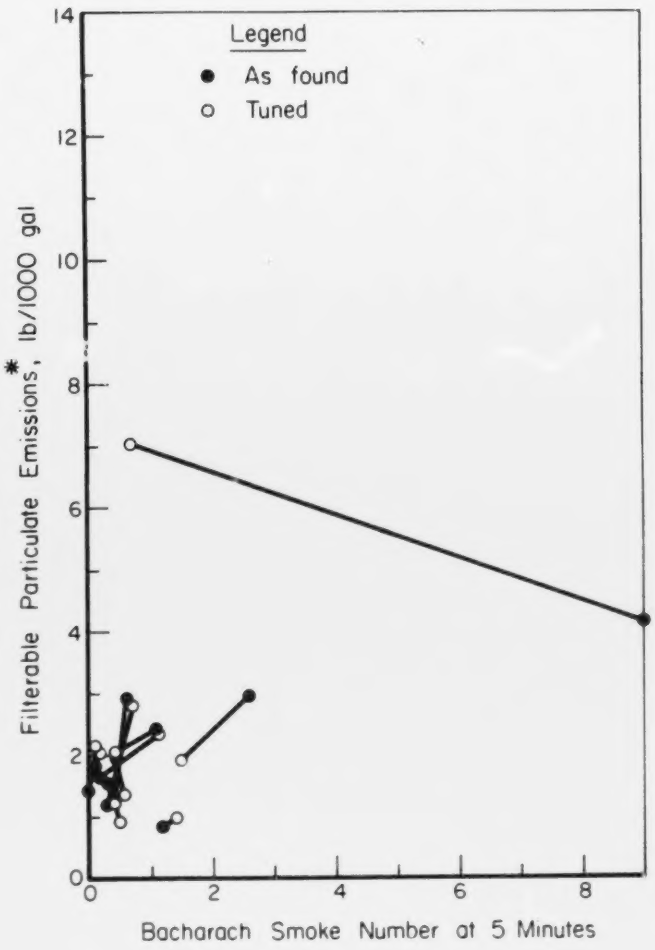

Figure II-23. Effect of Tuning on Smoke and Filterable Particulate Emissions for Individual – Phase II Residential Units

*Modified EPA Procedure.

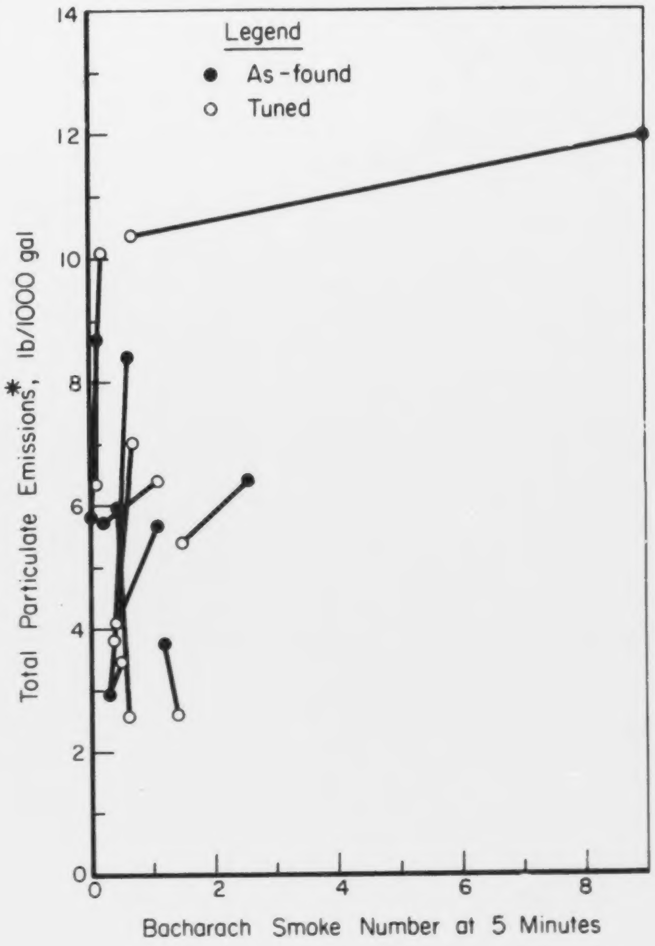

Figure II-24. Effect of Tuning on Smoke and Total Particulate Emissions for Individual – Phase II Residential Units

*Modified EPA Procedure.

the particulate integrated over the whole cycle, examination of the smoke readings taken at the 1,5, and 9-minute points of the "on" cycle (these data are reported in Table II-22) suggests that emissions may be extremely high during the first minute or two of firing.

Bacharach smoke samples, generally taken during essentially steady-state operation near the end of a cycle, do not include starting and shutdown as do the particulate samples. These transients show as peaks on gaseous monitors, as "smoke puffs" on the Von Brand continuous tape smoke meter, and as high smoke reading at the 1-minute point in Table II-22. These transients vary widely in degree for different units. The variation can be due partly to ignition delay and fuel pump cutoff characteristics, with the latter believed to be the most critical.

It should be recognized that only one particulate measurement was taken on each unit for each condition (as found and tuned), so there was no opportunity to determine if a correlation might exist between smoke and either steady-state or cyclic particulate for individual units without other changes.

Among the aspects which may be significant in the lack of correlation already observed between particulate weight and Bacharach smoke are particle size, density, and light reflection characteristics. It is hoped that particle-size measurements planned for a residential unit as follow-on to this program will help to clarify this aspect.

The planned experimental program will include particulate measurements taken during both cyclic and steady-state operation and may provide additional insight on the relation between smoke and these particulate levels for residential units.

Table II-22. Smoke Reading at 1, 5, and 9 Minutes for Cyclic Runs on Residential Units

Unit	Condition	Bacharach Smoke Number		
		1 Min	5 Min	9 Min
23	A	0.7	0.3	0.3
	T	0.6	0.5	0.5
	R	0.4	0.3	0.4
23.1	T	–	0.1	0.1
	R	–	0.2	0.1
23.2	T	–	0.0	0.0
	R	–	0.0	0.0
24	A	0.4	0.3	0.4
	T	3.0	0.7	0.7
	R	2.5	1.4	0.8
24.1	T	–	0.3	0.2
	R	–	0.2	0.1
24.2	T	–	0.5	0.2
	R	–	0.7	0.7
25	A	2.1	1.2	1.0
	T	1.7	1.4	1.7
	R	1.6	0.7	2.0
25.1	R	–	0.7	0.4
	R	–	0.2	0.1
25.2	T	–	4.1	4.1
	R	–	5.7	5.8
26	A	0.9	0.4	0.5
	T	0.9	0.6	0.4
	R	0.6	0.4	0.5
26.1	T	–	0.2	0.2
	R	–	0.2	0.2
26.2	T	–	0.5	0.5
	R	–	0.3	0.4
27	A	1.8	1.1	1.0
	T	0.8	0.4	0.4
	R	0.4	0.4	0.3
28	A	1.8	0.6	1.3
	T	1.1	0.4	0.4
	R	1.0	0.4	0.4
29	A	9.0	9.0	9.0
	T	2.3	0.7	0.5
	R	2.9	0.6	0.3

Table II-22. (Continued)

Unit	Condition	Bacharach Smoke Number		
		1 Min	5 Min	9 Min
30	A	0.4	0.2	0.2
	T	2.0	1.1	0.6
	R	2.5	0.4	0.3
31	A	0.2	0.0	0.0
	T	0.3	0.2	0.2
	R	0.3	0.3	0.2
32	A	0.7	0.1	0.2
	T	0.2	0.1	0.1
	R	0.1	0.1	0.1
33	A	Oily	Oily	Oily
	T	Oily	Oily	Oily
	R	Oily	Oily	Oily
34	A	3.0	2.6	2.7
	T	1.7	1.5	1.0
	R	1.7	1.6	1.9
35	T	0.3	0.2	0.2
	R	0.2	0.2	0.2

EMISSIONS FROM COMMERCIAL BOILERS

This chapter describes the Phase II investigation of emissions from commercial boilers. The principal effort of the Phase II program was on conducting a more detailed investigation of the effect of fuel, load, and excess air on emissions than was possible during the Phase I study. The discussion is presented as follows:

- Boilers Included in the Phase II Investigation
- Procedures used in the Field Investigation
- Emission Results for Commercial Boilers.

Where applicable, results of Phase I emission measurements[1] have been included in the analyses of the influence of various factors on emissions.

BOILERS INCLUDED IN THE PHASE II INVESTIGATION

The scope of boilers in the Phase II investigation included six commercial boilers ranging in size from 40 to 600 boiler horsepower firing various grades of fuel oils and natural gas.

Basis for Selection of Equipment

A survey of the commercial boiler population was initiated to form the basis for the selection of a representative mix of commercial boilers. A survey form (developed by the Battelle project team and project consultant W. H. Axtman) was distributed by the American Boiler Manufacturers Association (ABMA) to veteran observers in the commercial-industrial boiler industry. The results of this survey, summarized by W. H. Axtman, are contained in Appendix B.

Selection of Equipment Mix and Individual Boiler

The selection of the Phase II boiler mix and specific boiler type/size combinations was made by the Battelle-Columbus project team after reviewing results of the survey.

Boilers selected for inclusion in the Phase II study were intended to make the Phase II sample representative of the existing boiler population. (Phase I boilers did not weigh in this consideration due to the limited data obtained on these units.) It was decided that the Phase II study of commercial boilers was to provide so much more detailed information about emissions at various operating conditions, that the Phase II selections alone should be representative of the existing boiler population. The selection of the equipment mix and specific boiler type/size combinations was approved by the EPA Project Officer and the API SS-5 Task Force Steering Committee.

Table III-1 outlines the mix of commercial boilers included in the Phase I and II investigations as representative of commercial heating boilers in the field.

Table III-1. Mix of Commercial Boilers Sampled in Phases I and II

	Phases			Distribution of Sample by Percentage		Distribution of U.S. Commercial Boiler Population, percent[a]
	I	II	Total	Phase II	Total	
Total, all boilers[b]	7	6	13	–	–	–
By Boiler Size						
10-50 bhp	0	1	1	17	8	47
51-100 bhp	2	3	5	50	38	24
101-300 bhp	4	1	5	17	38	29
301-600 bhp	1	1	2	17	15	–
By Boiler Type						
Scotch	6	2	8	33	62	21
Firebox firetube	1	1	2	17	15	27
Cast iron	0	2	2	33	15	33
Watertube	0	1	1	17	8	6
Miscellaneous firetube	0	0	0	0	0	13
By Burner Type[b]						
Air atomizing	4	4	8	67	62	15
Pressure atomizing	2	2	4	33	31	22
Rotary atomizing	1	0	1	0	8	15
Natural gas	1	6	7	100	54	56
By Fuel[b]						
No. 2 oil	2	6	8	100	62	38
No. 4 & 5 oils[c]	4	5	9	83	69	8
No. 6 oil	2	3	5	50	38	4
Natural gas	1	6	7	100	54	56

[a] Commercial boilers are defined as between 50 and 300 bhp.

[b] Numbers total more than "Total, all boilers" because some boilers were fired with more than one fuel.

[c] Including Phase II reference fuel.

After review of the data obtained on boiler population and sales, it was determined that the six boilers be selected according to the size ranges of the survey: 10 to 50 bhp, 51 to 100 bhp, and 101 to 300 bhp. It was further decided that the two boilers selected in each size range be representative of the most common types for the size range. Hence, a tentative selection was made as follows:

- Size, 10 to 50 bhp
  Cast iron
  Firebox firetube
- Size, 51 to 100 bhp
  Cast iron
  Packaged Scotch
- Size, 101 to 300 bhp
  Packaged Scotch
  Firebox firetube.

These boiler selections were believed to be generally representative of boilers in the field today, within the limits placed by the size of the sample.

Another factor in the selection of the boilers was their capability for firing more than one fuel. The program plan was to fire each boiler with fuels as follows:

- No. 2 fuel oil
- A low-sulfur (1.0 percent) residual fuel oil typical of that being marketed on the East Coast
- Conventional No. 5 or No. 6 residual fuel oil
- Natural gas.

It was difficult to locate small boilers capable of firing heavier fuels; in fact, the smallest cast-iron boiler that was available could not be fired satisfactorily with fuels heavier than No. 2 grade fuel oil, in spite of several attempts by the manufacturer to successfully fire heavier fuels by switching burners. The larger cast-iron boiler could not fire conventional No. 5 and No. 6 grades of fuel oil but could fire No. 4 fuel oil and the low-sulfur residual fuel.

Midway in the program, it was learned that the tentatively selected 40-bhp firebox firetube boiler could not be fired with fuels heavier than No. 2 fuel oil. At that point, a substitution was made of a 600-bhp watertube boiler for the 40-bhp firebox firetube boiler. Thus, the scope of the boilers actually measured was expanded in both boiler size and boiler types. The EPA Project Officer and the API SS-5 Task Force Steering Committee concurred with this substitution.

For purposes of this investigation, it was important to select boilers for which load could be controlled at a desired level for extended periods to provide stable conditions for emission measurements. This requirement was met, through the cooperation of ABMA, by choice of equipment installed as house boilers or test boilers in plants of boiler manufacturers.* In addition, competent personnel already familiar with the specific equipment were available to adjust the boilers to the desired operating conditions. Normally, these boilers were in day-to-day operation to supply steam, to provide service training, or to provide a burner test facility for the manufacturing plants. These boilers did not appear to have received any better service attention than would be reasonably typical of similar boilers in commercial or industrial applications.

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*Boiler C2003 was an exception. It was a newly constructed unit that had been fired for manufacturers tests only. Emission measurements were made prior to its delivery by the manufacturer.

Description of Commercial Boilers

Table III-2 shows the number designation for each commercial boiler, with identification of boiler type and size, burner type, fuel grades, and other descriptive data.

PROCEDURES USED IN THE FIELD INVESTIGATION

The principal effort of Phase II of this investigation was devoted to more detailed field measurements of emissions covering more conditions than was possible for the Phase I study. Phase II was conducted during the heating season of 1971-72. The measurements were made by a three-man field team supported by other Battelle-Columbus staff.

Commercial boiler measurements were conducted in April through June 1972, with each boiler monitored for approximately 5 to 10 days, depending on conditions and fuels run.

The commercial boilers were all sampled in the as-found condition; i.e., no cleaning (except for the exhaust stacks) or other servicing of the units was done prior to measurements. Wherever practical, the exhaust stacks were thoroughly cleaned prior to sampling to minimize collection of previously deposited material during particulate sampling.

Conditions Investigated

Emission data from each of the commercial units were obtained under steady-state firing conditions at several excess air levels, generally while firing each of four fuels at four different load levels.

Load and Excess Air Conditions. Figure III-1 shows the matrix of runs that was the general plan or target for measurements on each boiler-fuel combination. A base-line condition, the operating condition most typical of normal boiler operating conditions, was defined as 80 percent load and 12 percent CO_2 (10 percent CO_2 for gas firing)*. The target loads were

R – rated load

H – 80 percent of load, considered the normal high-fire condition for boilers in use

M – an intermediate load

L – the normal low-fire setting.

Boiler C2001, a relatively small cast-iron boiler, normally operated strictly in the on-off mode; hence, intermediate loads could only be achieved by changing nozzle sizes. The remaining boilers were modulated to the desired loads.

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*The base-line condition was defined during the Phase I study after discussion with the ABMA Commercial-Industrial Air Pollution Committee.

Table III-2. Description of Commercial Boilers Included in Phase II Study

Boiler	Boiler Horsepower and Type	Burner Type	Normal Fuel Grade	Other Fuels[a]	Rated Input, gph	Output Rating, MBtu/hr	Method of Control	Operating Pressure, psig	Number of Flue Passes	Furnace Volume, cu ft[b]
C2001	40-hp Cast Iron	Pressure Atomizing	No. 2	Gas	11.35	1258	LFS[c] on/off	15	2[d]	19.7
C2002	90-hp Cast Iron	Air Atomizing	No. 4	No. 2, CR, Gas	26.1	3000	Modulating	15	2[d]	50.3
C2003	300-hp Scotch	Air Atomizing	No. 6	No. 2, CR, Gas	83.5	10043	Modulating	150	3	86.7
C2004	80-hp Firebox	Pressure Atomizing	No. 5	No. 2, CR, Gas	22.5	3341	LFS[c] on/off	15	3	40.8
C2005	100-hp Scotch	Air Atomizing	No. 6	No. 2, CR, Gas	28.0	3348	Modulating	15	4	25.4
C2006	600-hp Watertube	Air Atomizing	No. 6	No. 2, CR, Gas	165.2	25000	Modulating	150	2[d]	413.4

[a] CR used to designate 1 percent sulfur reference fuel fired in commercial boilers.

[b] Manufacturer's data; volume may include turn-around volume at rear of first pass.

[c] Low-fire start.

[d] Conventional flue pass definition not appropriate. These values were selected as the best approximation for these units.

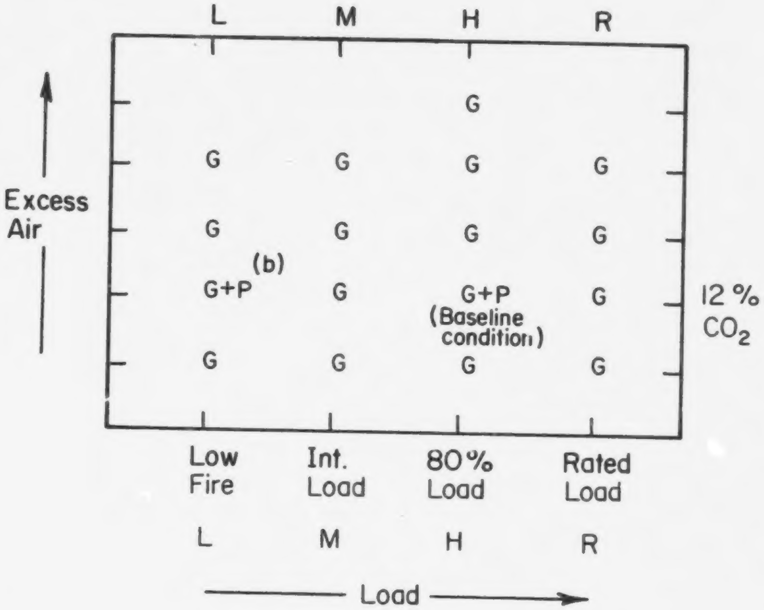

Figure III-1. Matrix of Measurement Points for Commercial Boilers[a]

a. G = Gaseous measurements, plus smoke
P = Particulate measurements.
b. Particulate was run at low load for normal house fuel only.

Air adjustments were made after disconnecting the air-fuel proportioning linkage. To assure a steady-state condition, the boilers were operated for at least 30 minutes at each load setting before sampling was started. Particulate samples were obtained for each boiler-fuel combination at the base-line condition. Additional particulate samples were obtained at the low-fire setting for each boiler while firing the normal fuel for the boiler. Gaseous emission measurements were obtained for each boiler-fuel combination at each load.

Fuels. As listed in Table III-2, each boiler was fired with the "house fuel" normally fired in the boiler, No. 2 fuel oil, a 1-percent sulfur East Coast residual oil designated CR* (for "commercial reference" oil), and natural gas. The commercial reference oil was typical of the current commercially available East Coast fuels at this sulfur level. It was purchased in Connecticut and transported from site to site in a 6000-gallon, steam-traced tank truck.

Properties of all fuel oils fired in commercial boilers are tabulated in Appendix C, Tables C-3 and C-4.

Boiler C2001, a small cast-iron boiler which could not fire heavy fuel oils, was fired with only No. 2 fuel oil and natural gas.

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*The designation CR is used to denote the particular fuel oil used as the commercial reference fuel in this study. LSR is used elsewhere in this report as a designator for the general class of low-sulfur residual fuel oils (1 percent sulfur) produced to meet local air pollution regulations.

Emission Measurements – Instruments and Techniques

The instrumentation and emission measurement techniques employed for the commercial units were similar to those used for the residential units.

An established set of operational procedures was routinely followed for each boiler investigated. Stack gases were sampled and supplied directly to continuous monitoring equipment set up alongside the heating unit.

Gaseous Emissions. Measurements were made of the following stack emissions under various conditions of operation using the methods noted as follows. (Details of instrumentation and measurement procedures are described in Appendixes E and F.)

Emission	Measurement Method
CO_2	NDIR (nondispersive infrared) and Fyrite
O_2	Amperometric and Fyrite
CO	NDIR
Hydrocarbons (total)	Flame ionization
SO_2	Dry electrochemical
NO_x	Dry electrochemical and NDIR with converter
NO	NDIR
Particulate	EPA sampling train.

Smoke and Other Combustion Parameters. Smoke was measured using the Bacharach hand pump smoke meter and the standard procedures adopted by ASTM[7]. In addition to these measurements, other combustion conditions measured included:

- Firing rate, by weight measurement
- Stack temperature, measured in the flue at the particulate sampling location
- Stack draft, measured in the flue at the particulate sampling location.

Particulate Emissions. Particulate emissions were sampled using the EPA sampling rig[2,8]. This train is described in Appendix F. A special feature of this sampling train is the inclusion of two water impingers or bubblers (at 70 F) downstream from the filter. The impingers were originally intended to collect any condensable material (at 70 F) that exist as vapor at filter temperature and, thus, pass through the filter and any solid particulate that pass through the filter. Recently, EPA has abandoned use of the impinger catch in determining particulate emissions for power plants[8] as there was indication that reactions occur in the impinger to generate material that is included in the weight measurement of particulate, even though the material does not exist as particulate either in the flue gas or in the atmosphere[9].

To insure that the most meaningful information was obtained from the particulate samples collected on this investigation, the probe wash, the filter catch, and the impinger wash were treated separately, and particulate weights were recorded for each. In this report, particulate data are reported as filterable (including the probe and filter catches) and total (combining the filterable and the material found in the water impingers). However, it should be pointed out that even the filterable catch obtained using the EPA sampling train may not be directly comparable to the particulate catch obtained using other sampling trains because of differences in the procedures for washing the probe and differences in sampling rates and volumes.

Previous experience at Battelle suggests that acetone washing may not be adequate to remove all particulate from the probe. Therefore, for this investigation two washing procedures were used: (1) the EPA procedure and (2) a modified EPA procedure referred to as the MEPA procedure. First, the probe, filter holder, and impingers were washed using procedures specified by EPA. Then a modified procedure was used wherein additional washings were made to insure complete removal of deposited particulate. The complete procedures and the resulting data are discussed further in Appendix F.

EMISSION RESULTS FOR COMMERCIAL BOILERS

This section summarizes the results obtained from measurements of gaseous and particulate emissions and smoke made on six commercial boilers during the Phase II investigation. Measurements were made on each boiler at several excess air levels at each of several loads; most were fired with four fuels. Results for the base-line condition (80 percent load and 12 percent CO_2) and analyses of the effect of important variables on emissions are presented in this section. Complete data for all runs for each boiler, each fuel, each load, and each excess air level are tabulated in Appendix H of the Data Supplement Volume.

In addition to the emission results, this section contains correlations showing the influence of various parameters (such as load, excess air, or fuel properties) on emissions.

Summary of Emission Data and Emission Factors

Table III-3 contains a summary of emission data for the commercial boilers. Table III-4 shows emissions in lb/1000 gal oil for the gaseous pollutants (CO, HC, NO_x, and SO_2) and for particulate for each boiler-fuel combination at the base-line condition.

Table III-3. Summary of Emissions From Commercial Boilers at the Base-Line Conditions[a]

	Operational Data								Emissions						
									Gases, ppm					Particulate[d], mg/sm^3	
Commercial Boiler[b]	Fuel Grade	Fuel Temp, F	Firing Rate, gph[c]	Load, %	CO$_2$, %	O$_2$, %	Excess Air, %	Bacharach Smoke No.	CO	HC	NO	NO$_x$	SO$_2$	Filterable	Total
C2001	No. 2	–	9.3	80	12.1	4.4	26	2.4	14	1.5	61	62	142	11.0	50.1
	Gas	–	1.26	81	9.1	5.0	27	0.2	51^e	35^e	71^e	75^e	0^e	5.2^e	18.0^e
C2002	No. 2	–	21.6	78	11.9	5.3	30	0.6	4.0	0.5	75	74	140	11.3	22.7
	No. 4	–	20.6	78	12.3	4.3	25	2.3	2.0	–	247	251	900	39.9	57.5
	CR	195	20.4	78	12.1	4.4	26	3.0	0	–	257	257	520	106	122
	Gas	–	3.04	82	10.0	3.3	16	0.1	1.0	0.3	93	94	0	4.8	15.5
C2003	No. 2	88	71.5	80	12.1	4.9	27	2.0	0	3.0	70	70	86	15.9	29.6
	CR	143	66.0	77	12.0	4.5	27	3.1	2.0	1.2	189	190	520	292	313
	No. 6	208	65.5	79	11.9	5.0	30	4.2	9.0	3.2	250	250	1150	738	762
	Gas	–	10.0	83	10.0	3.2	16	0.0	5.0	1.0	113	116	0	10.0	24.5
C2004	No. 2	–	19.2	81	12.0	4.5	26	0.2	0	1.8	103	104	102	15.8	24.9
	CR	118	18.3	82	12.1	4.2	25	2.9	0	5.3	251	249	500	73.7	110
	No. 5	120	18.4	85	12.0	4.8	30	5.0	0	3.7	291	295	1160	144	210
	Gas	–	2.40	76	10.0	3.6	17	0.0	8.0	3.0	47	50	0	7.7	13.4
C2005	No. 2	85	23.6	76	12.0	4.3	26	0.0	0	2.6	125	127	180	10.8	43.1
	CR	110	22.5	77	12.1	4.5	26	2.5	0	1.0	238	243	550	49.0	74.6
	No. 6	206	21.8	77	12.1	5.3	31	3.8	5.0	1.0	293	301	930	108	160
	Gas	–	3.21	77	10.0	3.0	16	0.1	67	8.0	63	65	0	8.1	23.0
C2006	No. 2	70	142	79	11.9	3.8	25	0.4	0	4.7	124	123	86	6.6	20.8
	CR	127	143	84	12.0	4.0	25	3.4	0	6.2	210	208	520	71.0	99.9
	No. 6	212	139	84	12.1	4.1	27	4.1	0	4.2	263	266	660	246	297
	Gas	–	20.1	83	9.8	2.4	15	0.0	0	3.2	95	95	2	7.2^e	14.8^e

(a) Base-line condition is 80 percent and 12 percent CO$_2$ (10 percent CO$_2$ for gas firing).

(b) See Table III-2 for descriptions of boilers.

(c) Firing rate is 10^3 cfh for gas firing.

(d) Particulate by modified EPA procedure.

(e) Emission data at 9.0 percent CO$_2$.

Table III-4. Summary of Emission Factors for Commercial Boilers at the Base-Line Conditions[a]

			Emission Factors, lb/1000 gal[c]					
Commercial Boiler[b]	Fuel Grade	Bacharach Smoke No.	Gaseous Emissions				Particulate[d]	
			CO	HC	NO_x	SO_2	Filterable	Total
C2001	No. 2	2.4	1.7	0.11	12.5	40.0	1.2	5.4
	Gas	0.2	6.6[e]	2.60[e]	16.0[e]	0.0[e]	0.6[e]	1.9[e]
C2002	No. 2	0.6	0.5	0.04	15.7	40.8	1.3	2.5
	No. 4	2.3	0.3	–	53.2	265.6	4.5	6.5
	CR	3.0	0.0	–	55.3	155.8	12.1	13.9
	Gas	0.1	0.1	0.02	18.2	0.0	0.4	1.5
C2003	No. 2	2.0	0.0	0.21	14.4	24.6	1.7	3.2
	CR	3.1	0.3	0.09	41.2	156.8	33.6	35.9
	No. 6	4.2	1.3	0.25	56.9	364.3	89.1	92.1
	Gas	0.0	0.6	0.07	22.4	0.0	1.0	2.5
C2004	No. 2	0.2	0.0	0.13	21.0	28.6	1.7	2.7
	CR	2.9	0.0	0.40	53.7	148.9	8.4	12.5
	No. 5	5.0	0.0	0.29	67.0	366.8	17.3	25.3
	Gas	0.0	1.0	0.20	9.8	0.0	0.7	1.3
C2005	No. 2	0.0	0.0	0.18	25.6	50.4	1.2	4.6
	CR	2.5	0.0	0.08	52.4	165.2	5.6	8.5
	No. 6	3.8	0.7	0.08	70.2	301.8	13.3	19.8
	Gas	0.1	7.8	0.54	12.5	0.0	0.9	2.2
C2006	No. 2	0.4	0.0	0.33	24.6	23.8	0.8	1.4
	CR	3.4	0.0	0.46	44.9	154.6	8.0	11.3
	No. 6	4.1	0.0	0.33	59.2	204.6	29.1	35.1
	Gas	0.0	0.0	0.21	18.1	0.0	0.8[e]	1.6[e]

(a) Base-line condition is 80 percent load and 12 percent CO_2 (10 percent CO_2 for gas firing).

(b) See Table III-2 for descriptions of boilers.

(c) Emission factors for gas firing are given as an equivalent thermal basis to lb/1000 gal of oil, e.i., in lb/(145 x 10^6 Btu).

(d) Particulate by modified EPA procedure.

(e) Emission factor at 9.0 percent CO_2.

CO and HC emissions are generally low except for occasional gas-fired runs, particularly for Boilers C2001 and C2005. The reason for these occasional high emissions is not evident and it is not reflected in smoke number, as the smoke was very low for all gas runs listed in this table. SO_2 emissions are related directly to fuel sulfur and are relatively unaffected by combustion conditions.

The emissions that are affected by boiler design or operation (namely, NO_x, smoke, and particulate) are of prime interest and are discussed separately below.

Influence of Various Parameters on NO_x Emissions

NO_x emissions from combustion sources are known to be generated by two processes – oxidation of organic nitrogen bound in the fuel and by thermal fixation of nitrogen in the combustion air in the furnace environment. Hence, NO_x emissions are related to nitrogen content of the fuel[10,11], combustion temperature, and the relative competition for oxygen atoms (i.e., whether conditions are oxidizing or reducing and to what extent[12]. Therefore, it is useful to examine the influence on NO_x emissions of fuel nitrogen and the major factors which influence combustion temperature and oxygen availability (such as load and excess air). The effect of these factors on NO_x emissions was investigated in this program and the results are discussed below.

In addition to considering the influence of the obvious parameters on NO_x emissions, a regression analysis was used to determine the best equation relating the NO_x data for the base-line condition to additional fuel and equipment variables. Variables included in this analysis were as follows:

Fuel Variables

Fuel nitrogen, N

$N^{1/2}$

API gravity

Specific gravity

Carbon residue (Ramsbottom)

Viscosity at firing temperature, V (SSU)

Carbon content, C

Hydrogen content, H

$\frac{C}{H}$

$\frac{C}{N}$

$\frac{C}{H+N}$

Boiler Variables

Firing rate

Combustion volume

Combustion intensity, CI
(firing rate per unit combustion volume)

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[10] Martin, G. B., and Berkau, E. E., "An Investigation of the Conversion of Various Fuel Nitrogen Compounds to Nitrogen Oxides in Oil Combustion", presented at AIChE Meeting, Atlantic City, N.J., August 30, 1971.

[11] Turner, D. W., Andrews, R. L., and Siegmund, C. W., "Influence of Combustion Modification and Fuel Nitrogen Content on Nitrogen Oxides Emissions From Fuel Oil Combustion", presented at AIChE Meeting, San Francisco, November 28-December 2, 1971.

[12] Bartok, W., Crawford, A. R., Cunningham, A. R., Hall, H. J., Manny, E. K., and Skopp, A., "Systems Study of Nitrogen Oxide Control Methods for Stationary Sources", Final Report, Esso Res. & Engrg. Co., November 20, 1969, NAPCA Contract PH-22-68-55.

The best equations that could be fit to the NO_x data using these variables were as follows:

Using only one variable

NO_x (ppm at 3 percent O_2) = 89.97 + 834.7·N (percent)

Using more than one variable

NO_x (ppm at 3 percent O_2) = 9.10 + 579.2·N (percent) + 0.373·V (SSU) + 101.3·CI (Btu/ft^3).

The correlation of NO_x with one variable, N, was 0.81. The correlation coefficient obtained using the three variables listed in the above equation was 0.85.

Correlation coefficients with NO_x emissions obtained when each of the above listed variables was considered are as follows:

Variable	Correlation Coefficient (Absolute Value)
Fuel nitrogen, N	0.81
$N^{1/2}$	0.79
API Gravity	0.77
Specific gravity	0.77
Carbon residue, Ramsbottom	0.73
Hydrogen content, H	0.71
$\frac{C}{H}$	0.70
$\frac{C}{H}$	0.69
$\frac{C}{H+N}$	0.63
Viscosity at firing temperature, SSU	0.62
Carbon content, C	0.45
Firing rate per unit combustion chamber volume	0.42
Firing rate	0.10
Combustion chamber volume	0.07

It should be noted that the correlation coefficients were higher for all the fuel variables considered than for the boiler-related variables. Thus, either the fuel is the significant factor in NO_x formation (which is certainly true for NO_x formed from fuel nitrogen) or the most appropriate boiler variables were not considered (true to the extent that flame characteristics were not available).

NO_x and Fuel Nitrogen. Due to the complexity of NO_x emissions (with the thermal NO_x varying from boiler to boiler and the fuel NO_x varying from fuel to fuel), several different approaches were used to examine the relationship of NO_x and fuel nitrogen.

Figure III-2 shows the measured NO_x emissions plotted against fuel nitrogen for all Phase I and II runs firing fuel oils in commercial boilers at the base-line conditions (80 percent

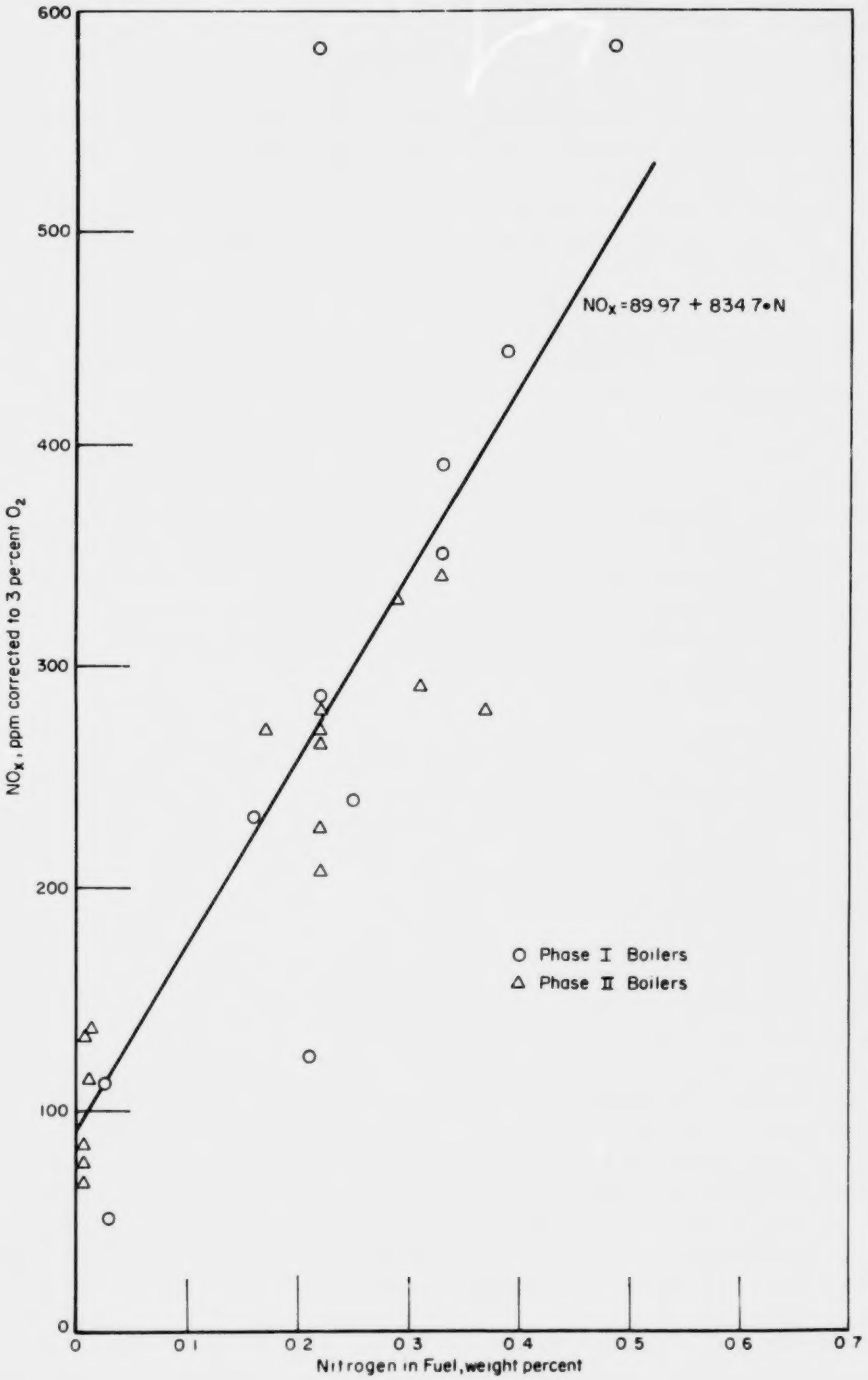

Figure III-2. Relation of NO_x to Fuel Nitrogen for Phases I and II, Commercial Boilers Fired at Base-Line Conditions

load and 12 percent excess air). Except for a few data points, a strong relationship is evident between NO_x emissions and fuel nitrogen. The curve obtained from the regression analysis (with one variable term) described above is also shown in Figure III-2. This curve has a slope equivalent to a 65 percent conversion of fuel nitrogen to NO_x.*

Figure III-3 shows the relationships between NO_x emissions and fuel nitrogen for each of the six boilers included in the Phase I and II studies that were fired with more than one fuel. The slopes of these curves are generally similar to the slope of the line showing a conversion rate of 60 percent of the fuel nitrogen to NO_x. No correlation is evident between the shapes of the curves and/or the zero-fuel-nitrogen intercepts and the boiler variables, such as firing rate or combustion intensity.

To obtain a better understanding of the influence of fuel nitrogen on NO_x emissions, the following analysis was performed using data for boilers in which No. 2 fuel oil (a low nitrogen fuel) and heavier oils were fired. The **thermal NO_x** for each boiler was estimated by assuming 100 percent conversion of all fuel nitrogen from firing of No. 2 fuel oil and subtracting this fuel nitrogen term from the NO_x measured when firing No. 2 fuel oil. The **fuel nitrogen term** for each boiler and fuel combustion was estimated by subtracting the thermal NO_x term for that boiler from the measured NO_x value. The fuel nitrogen components were plotted against fuel nitrogen, see Figure III-4, and a curve was drawn to fit the data by eye. The best curve to fit the data was of the form NO_x (ppm) = Thermal NO_x + $420 \cdot N^{0.6}$. The overall thermal NO_x term was estimated by averaging the thermal NO_x terms for each boiler: the average value is 97 ppm. Hence, the best estimate of NO_x from the Boilers C2001 through C2006 (the boilers in which No. 2 and heavier fuel oils were fired was:

$$NO_x, \text{ ppm} = 97 + 420\ N^{0.6}$$

(In the range of fuel nitrogen from 0.0 to 0.06 percent, this equation predicts NO_x from fuel nitrogen that exceed 100 percent conversion of fuel nitrogen but the maximum error is about 10 ppm, less than the variation in thermal NO_x from one boiler to another.)

NO_x and Excess Air. Figures III-5 through III-10 show the sensitivity of NO_x emissions to excess air for all fuels and boilers at 80 percent load. NO_x emissions are expressed in lb/10^6 Btu for these figures, as this is the most meaningful value when comparing widely varying fuels: e.g., natural gas and No. 6 fuel oil.

Examination of the relationship of NO_x to excess air, shown in Figures III-5 to III-10, suggests that NO_x tends to be relatively constant or increases slightly with excess air. Apparently, the increase in oxygen concentration promotes NO_x formation to a greater degree than the increased excess air tends to cool the flame. In nearly all cases, the variation of NO_x with excess air within the normal range of excess air – 15 to 30 percent – was 12 percent or less. (The exceptions were firing No. 4 fuel oil and the CR reference fuel in Boiler C2002, where the variation of NO_x with excess air was large inthe 15 to 20 percent excess air range.)

It is interesting to compare the NO_x emission shown in Figures III-5 to III-10 with the EPA standards for NO_x emission from new fossil-fuel power plants[2]. These standards permit NO_x emissions of 0.20 lb/10^6 Btu for gas-fired boilers and 0.30 lb/10^6 Btu for oil-fired boilers. From the commercial boilers and fuels examined, these standards were met in each case for No. 2 fuel oil and gas firing. Conversely, for each boiler the NO_x emission standard for oil firing could not be met when firing conventional No. 5 or 6 fuel oils. When firing the commercial

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*One percent fuel nitrogen converted to NO_x yields about 1280 ppm of NO_x at 3 percent O_2.

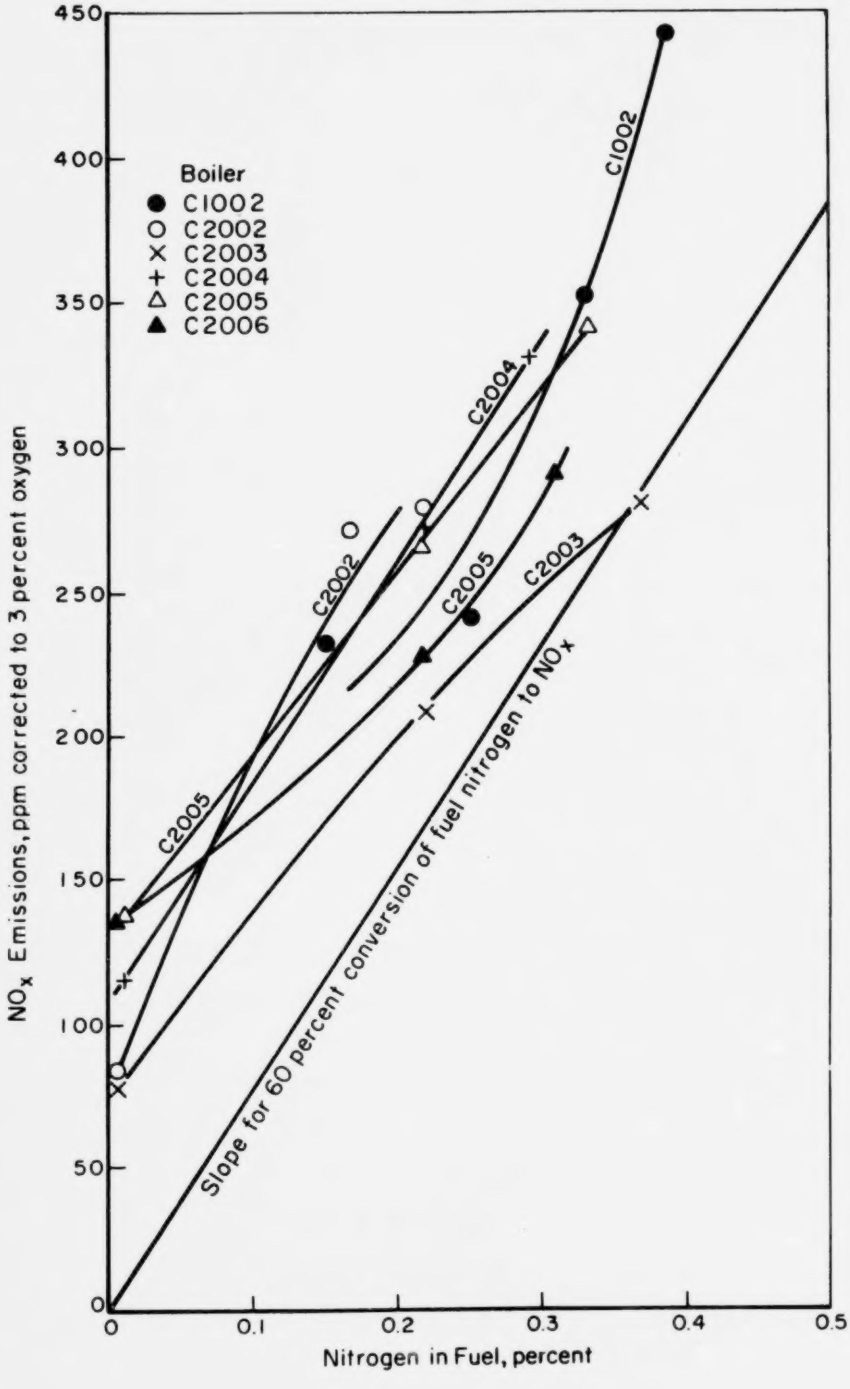

Figure III-3. Relation of NO$_x$ Emissions to Fuel Nitrogen for Commercial Boilers Operated at 12 Percent CO$_2$ and 80 Percent Load

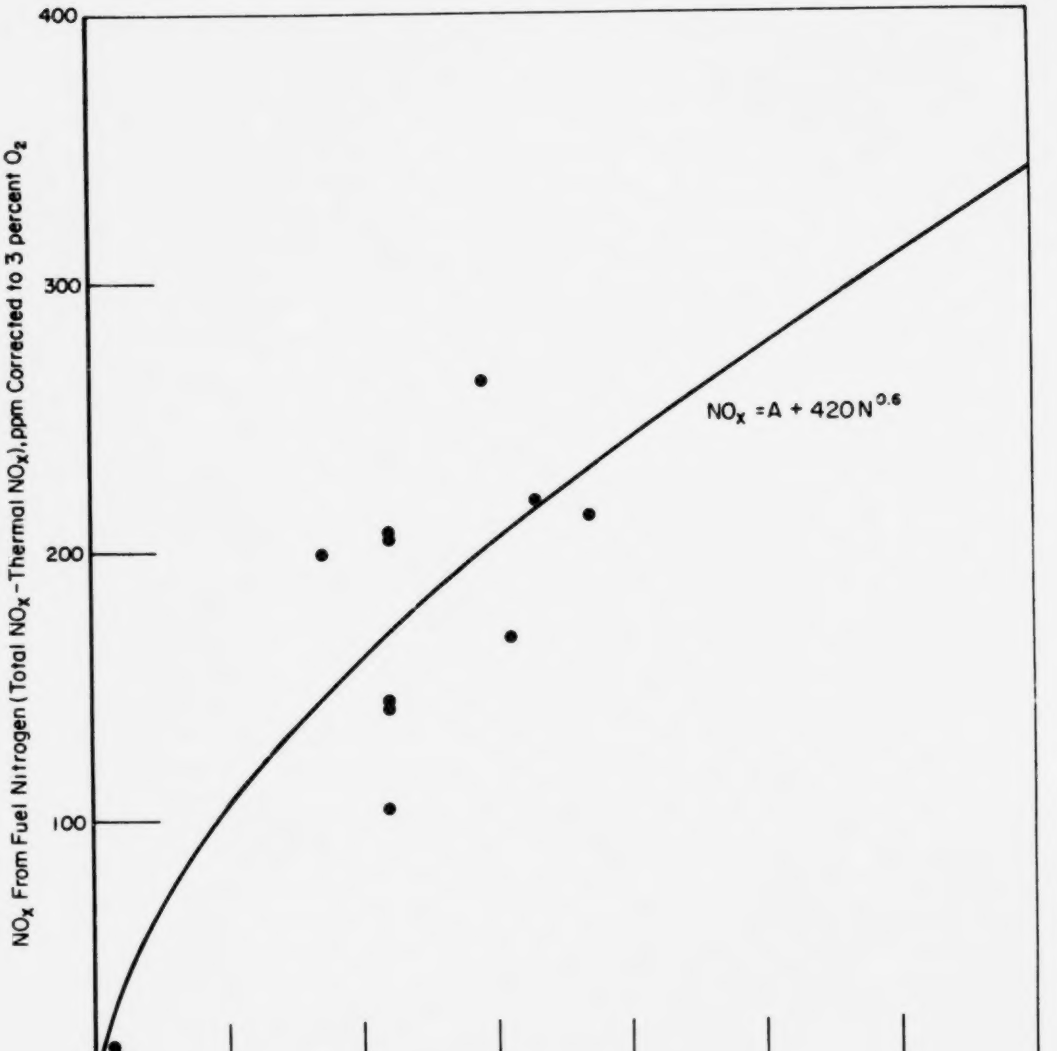

Figure III-4. Relationship of NO$_x$ from Fuel Nitrogen to Fuel Nitrogen for Boilers Firing No. 2 and Heavier Fuel Oils

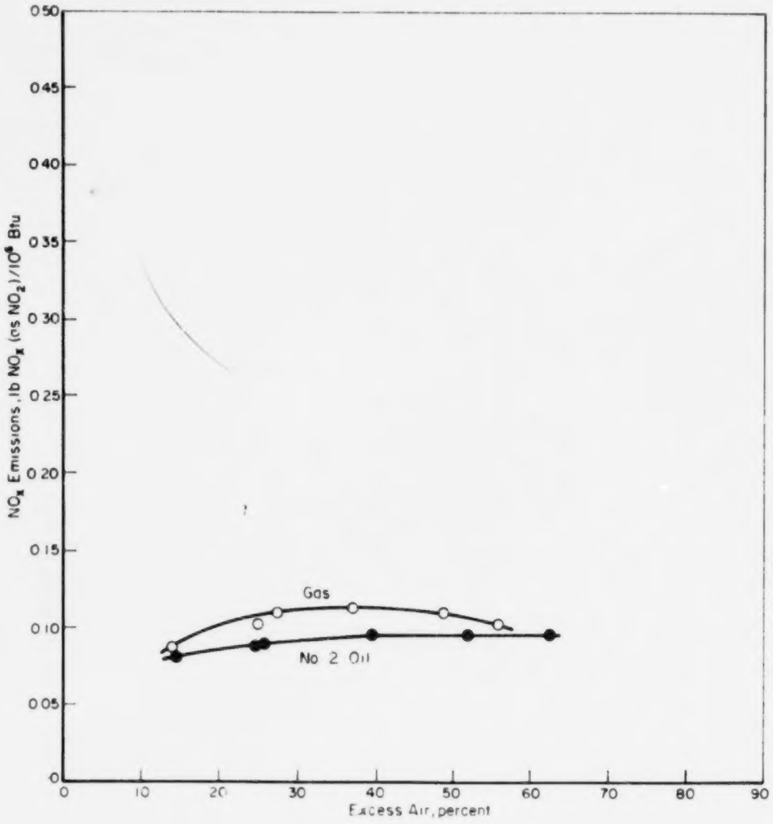

Figure III-5. Relation of NO_x Emissions to Excess Air for Boiler C2001 at 80 Percent Load

40-bhp Cast Iron Boiler.

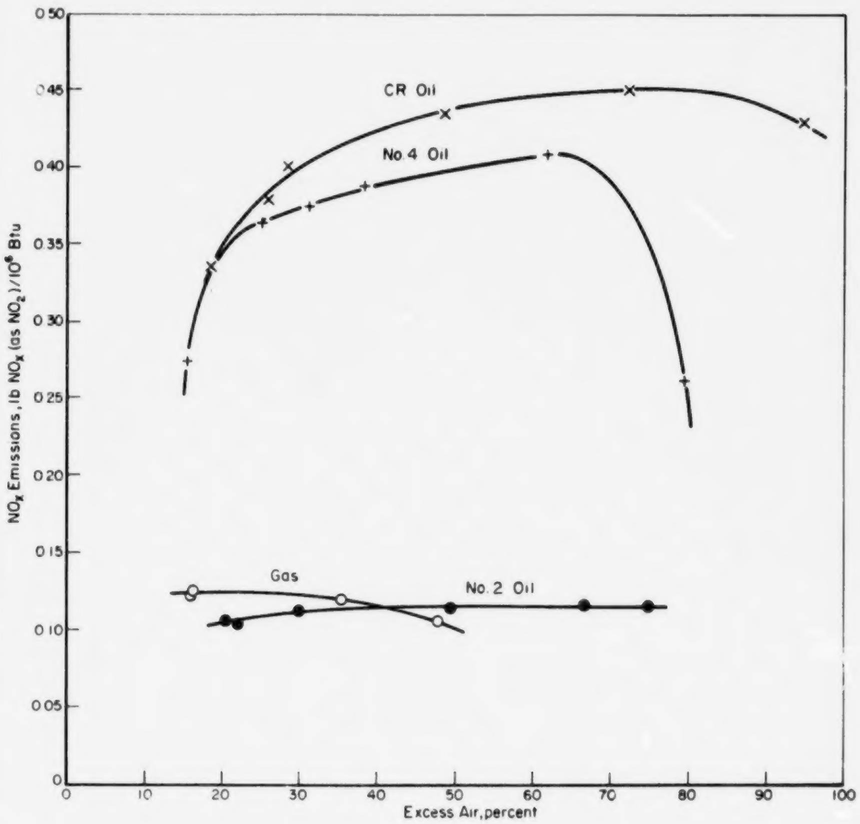

Figure III-6. Relation of NO_x Emissions to Excess Air for Boiler C2002 at 80 Percent Load

90-bhp Cast Iron Boiler.

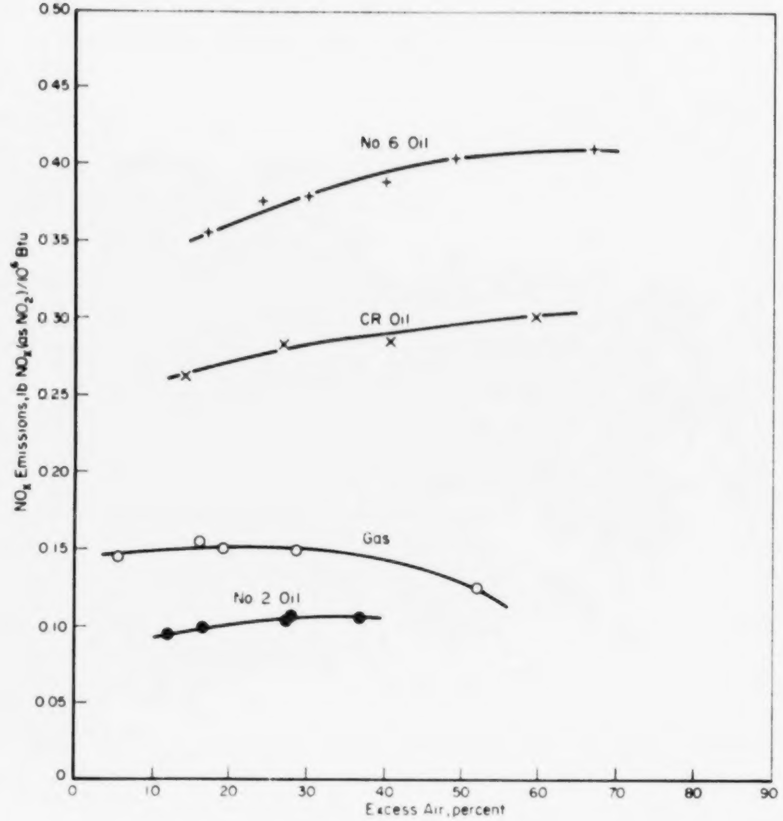

Figure III-7. **Relation of NO_x Emissions to Excess Air for Boiler C2003 at 80 Percent Load**

300-bph Scotch Boiler.

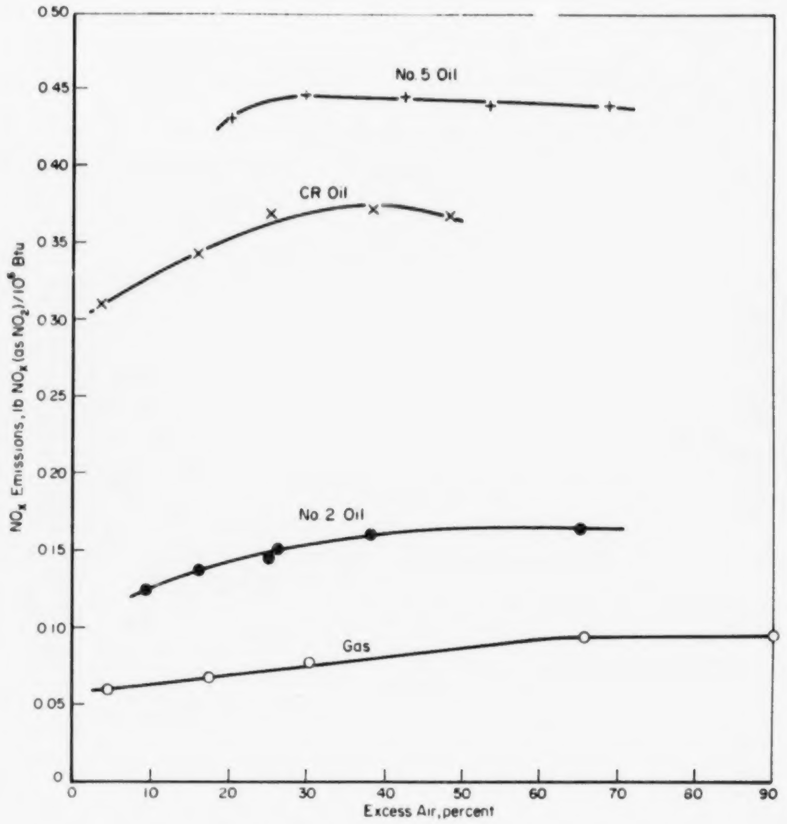

Figure III-8. **Relation of NO_x Emissions to Excess Air for Boiler C2004 at 80 Percent Load**

80-bhp Firebox Boiler.

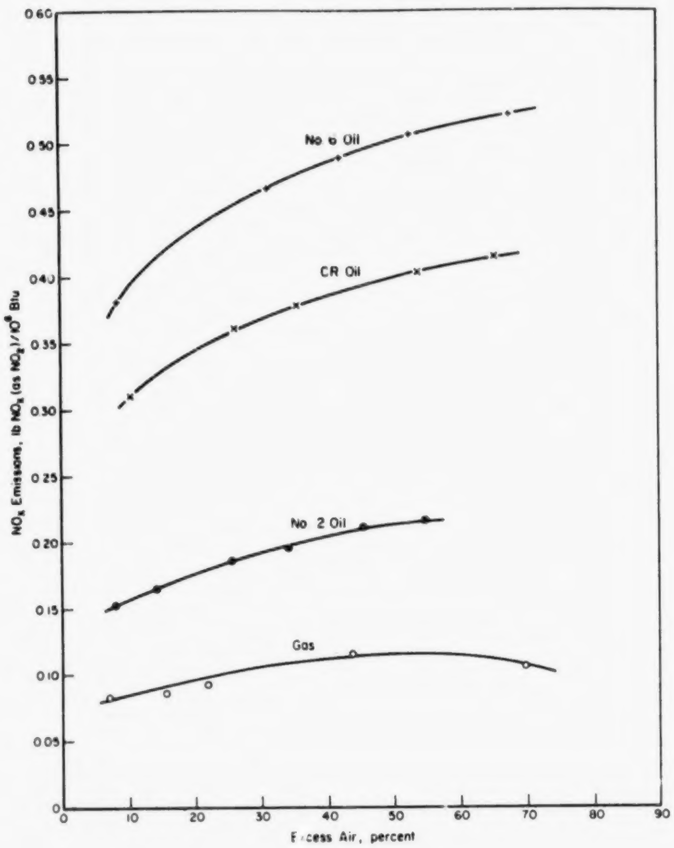

Figure III-9. Relation of NO_x Emissions to Excess Air for Boiler C2005 at 80 Percent Load

100-bhp Scotch Boiler.

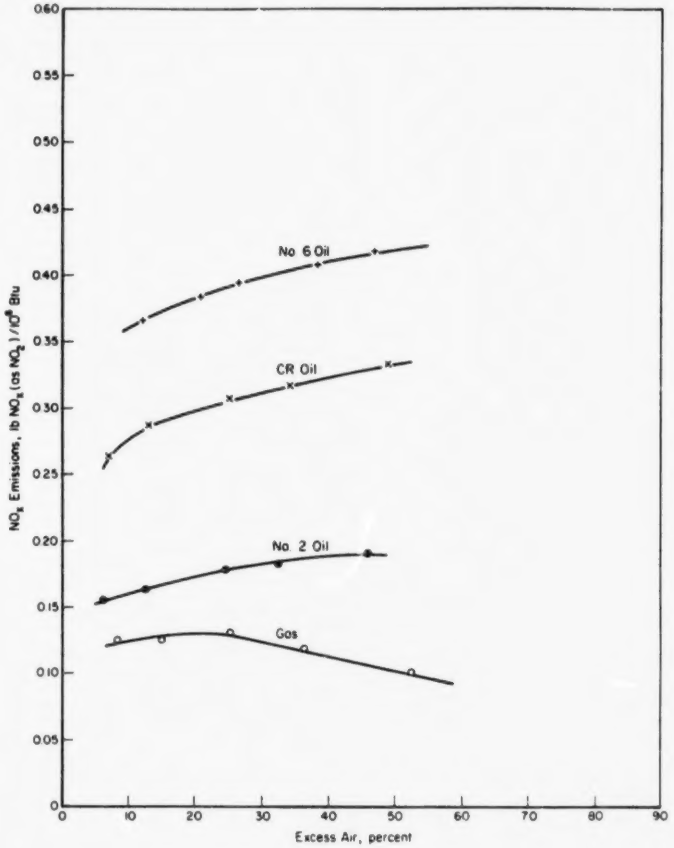

Figure III-10. Relation of NO_x Emissions to Excess Air for Boiler C2006 at 80 Percent Load

600-bhp Watertube Boiler.

reference fuel, CR, the standard could be attained at low excess air levels in some boilers but could not be attained in other boilers.

NO_x and Load. Figures III-11 through III-16 show the relationship between NO_x emissions and load for each boiler and each fuel for the nominal 12 percent CO_2 condition. Load does not seem to be a critical factor influencing NO_x emissions. For most boilers, the NO_x emissions were relatively constant over the range of load investigated. Boilers C2002 and C2003 exhibited a trend of NO_x increasing with load for the heavier fuels. NO_x emissions from Boiler C2005 were quite high at low load.

NO_x for Gas Firing. As expected, gas firing of the commercial boilers produced relatively low NO_x emissions. The NO_x emissions from boilers fired along the East Coast (Boilers C2001, C2002, and C2003 were located in New England and Eastern Pennsylvania) averaged 99 ppm at 3 percent O_2. NO_x emissions from boilers in the Midwest (Boilers C2004, C2005, and C2006 were located within 200 miles of Chicago) averaged 70 ppm.

It is interesting to compare NO_x emissions for gas firing with those for firing with No. 2 fuel oil, as shown in Table III-5. For the boilers located in the East, the NO_x from gas firing exceeded that from No. 2 fuel oil. Conversely, in the boilers located in the Midwest, the NO_x from firing No. 2 fuel oil exceeded that from gas. The fuel nitrogen levels of the No. 2 fuel oils fired in the Midwest were slightly higher than those for oils fired in the East. However, the difference would only account for 3 ppm at a conversion efficiency of 100 percent.

Table III-5. NO_x Emissions for Phase II Boilers Firing Natural Gas and No. 2 Fuel Oil

	NO_x Emissions, equivalent ppm at 3 percent O_2 and 80 percent load		
Boiler	Gas	No. 2 Fuel Oil	N Content No. 2 Oil, percent
C2001	84	67	0.0084
C2002	95	85	0.0084
C2003	117	77	0.0078
C2004	51	114	0.0113
C2005	65	138	0.0124
C2006	95	134	0.0086

The relative differences in NO_x emissions from gas- and oil-fuel boilers in the East and Midwest may be attributable to different burner adjustment practices in the two regions or some other subtle variable(s).

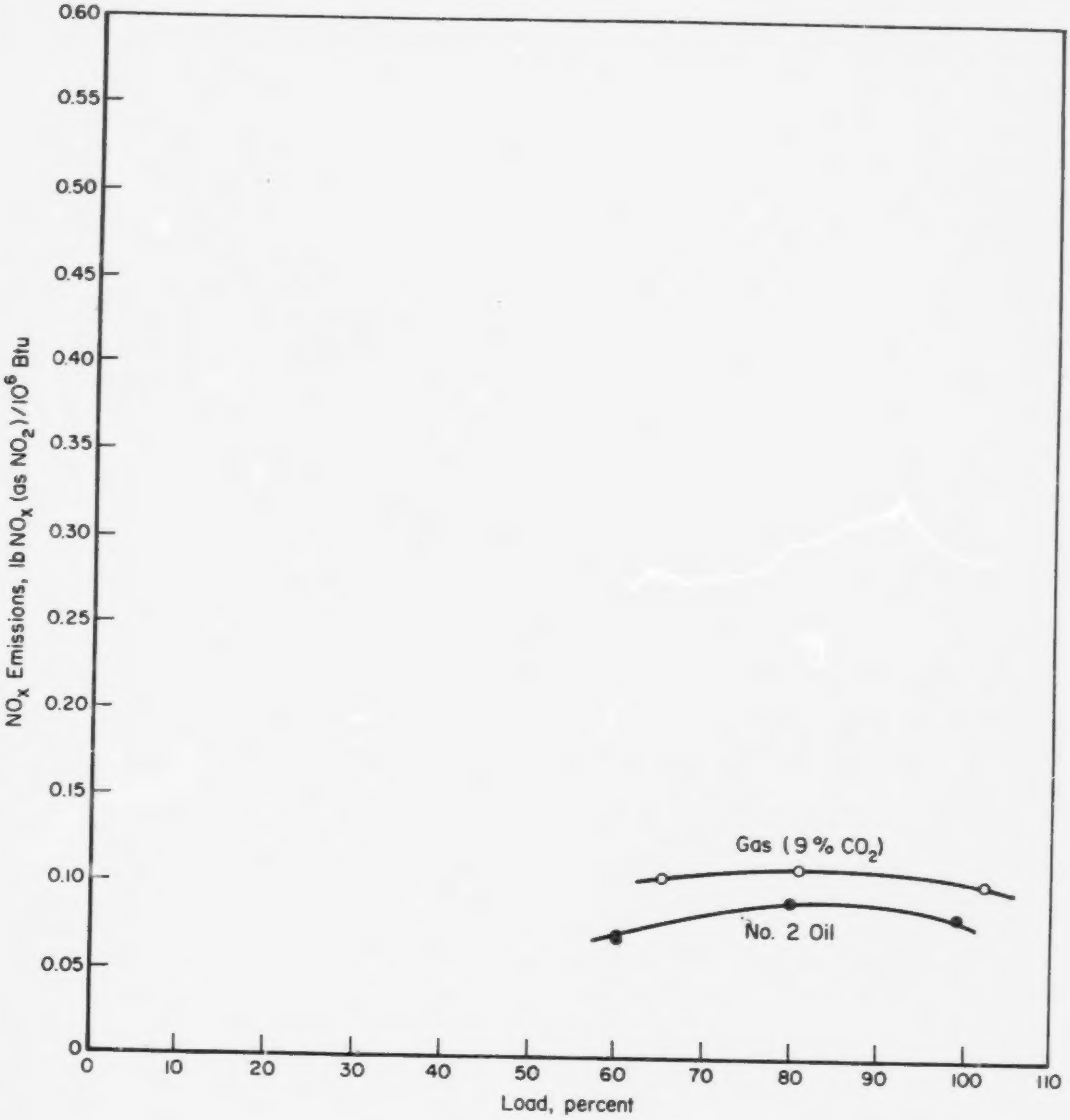

Figure III-11. Relation of NO_x Emissions to Load for Boiler C2001 at 12 Percent CO_2 40-bhp Cast Iron Boiler.

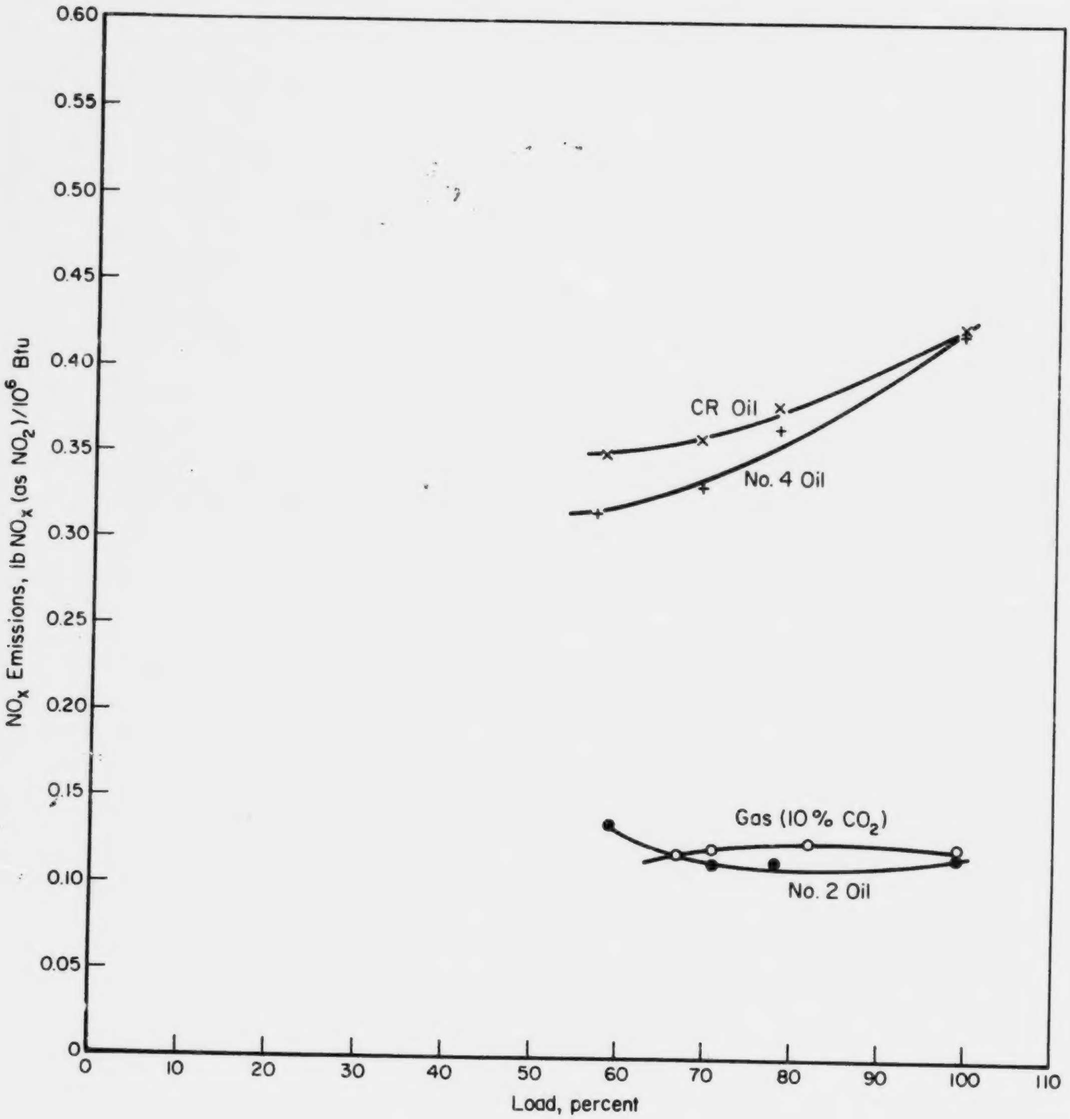

Figure III-12. Relation of NO$_x$ Emissions to Load for Boiler C2002 at 12 Percent CO$_2$

90-bhp Cast Iron Boiler.

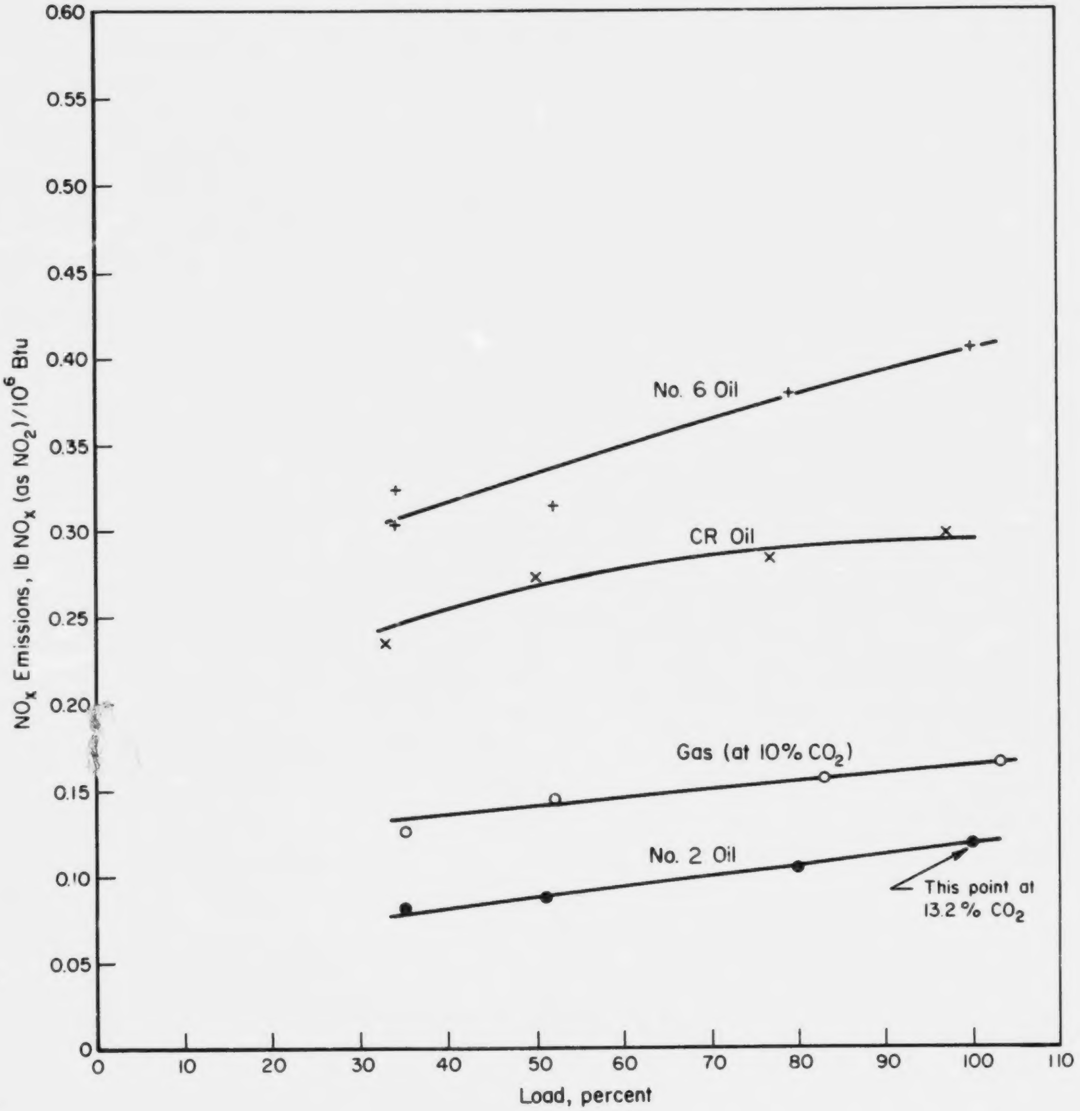

Figure III-13. Relation of NO$_x$ Emissions to Load for Boiler C2003 at 12 Percent CC$_2$

300-bhp Scotch Boiler.

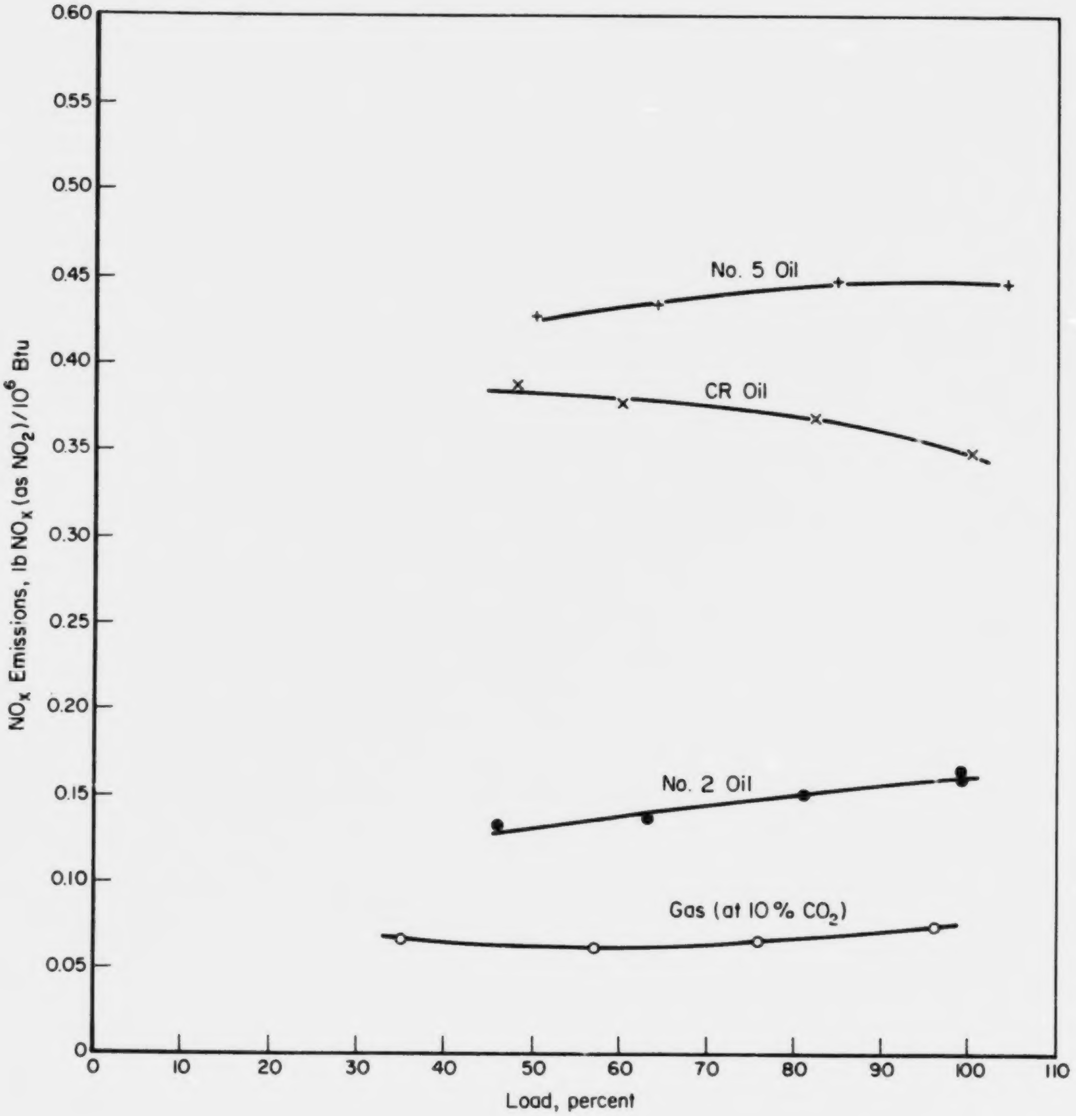

Figure III-14. Relation of NO_x Emissions to Load for Boiler C2004 at 12 Percent CO_2 80-bhp Firebox Boiler.

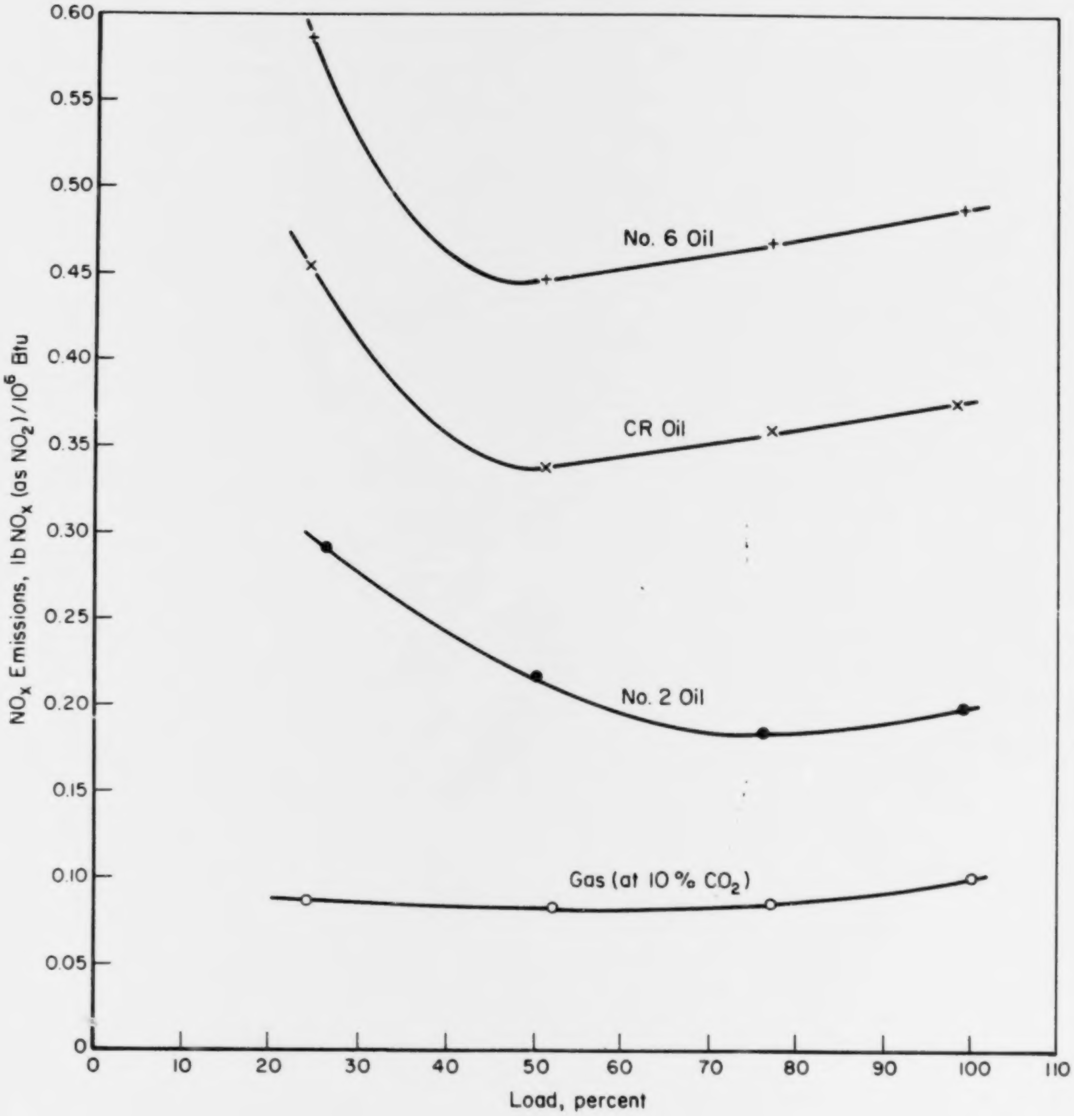

Figure III-15. Relation of NO$_x$ Emissions to Load for Boiler C2005 at 12 Percent CO$_2$

100-bhp Scotch Boiler.

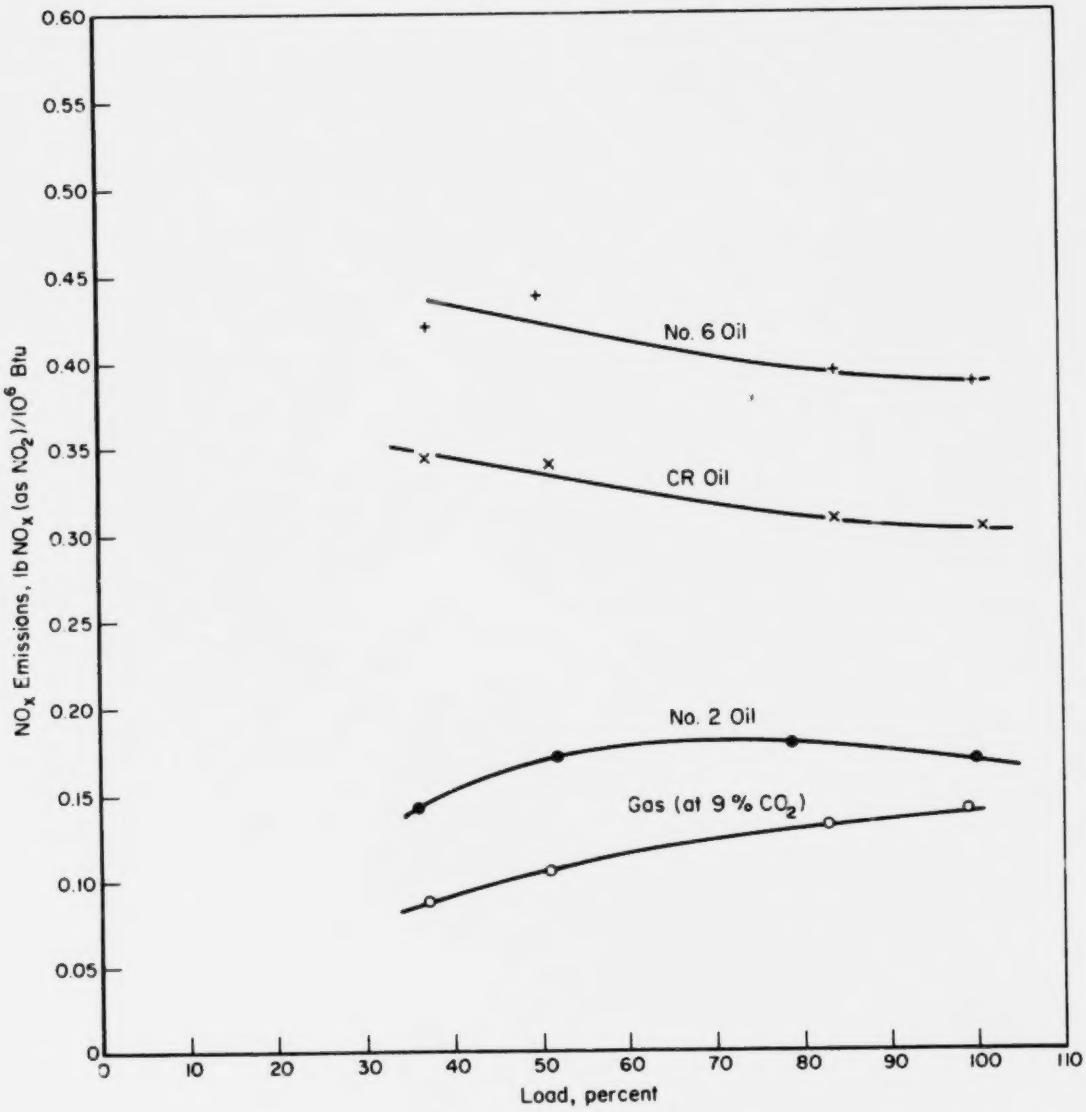

Figure III-16. Relation of NO$_x$ Emissions to Load for Boiler C2006 at 12 Percent CO$_2$ 600-bhp Watertube Boiler.

Influence of Operating Condition on Smoke, CO, and HC Emissions

In this program, two parameters were examined that defined operating conditions – excess air and load. The following discussion presents results showing the influence of each of these parameters on smoke, CO, and HC emissions. (Their influence on NO_x emissions was described earlier.)

Excess Air. Figures III-17 through III-22 show the relation of smoke and CO emissions to excess air for each fuel fired in each boiler at 80 percent load. HC emissions are not shown on these figures, as they were nearly always low; when high HC emissions were measured, the CO emissions were also high. Hence, CO was selected to illustrate emission trends for both CO and HC.

Figures III-17 through III-22 show that about 30 percent excess air is required to fire most fuel oils in the Phase II boilers to avoid smoke levels above about Bacharach No. 2 or 3. In a few cases (No. 6 fuel oil in boiler C2003 and No. 5 fuel oil in boiler C2004), the smoke remained high even at excess air levels above 30 percent.

Gas could generally be fired at 10 percent excess air without exceeding a No. 1 smoke level. However, 20 percent excess air generally was required to avoid high levels of CO emissions.

Smoke Number as an Indicator of CO and HC Emissions. Examination of the curves of smoke, CO, and HC emissions plotted against excess air* shows that, as the excess air was decreased for oil-fired boilers, the smoke level tended to increase before the CO and HC emissions increased. However, as the excess air was decreased for gas-fired boilers, the CO and HC emissions generally increased before the smoke level increased. Hence, setting the excess air for an oil-fired boiler by smoke number will tend to keep CO and HC emissions at a minimum. Conversely, setting the excess air level by smoke number for gas-fired boilers does not insure minimum CO and HC emissions.

Load. Generally, load did not significantly influence emissions of CO and HC. For two boilers (C2003 and C2004), smoke tended to increase as load was decreased at constant CO_2. For the remaining boilers, changes in load did not significantly affect smoke.

Based on conversations with commercial boiler/burner specialists – namely, members of the ABMA Commercial-Industrial Air Pollution Committee – it was determined that commercial boilers generally operate most of the time at one of two loads – a high load of about 80 percent of rated load and a low fire condition. Once a boiler is in service, the serviceman is likely to adjust the burner to produce low smoke at these two normal operating conditions. Hence, the influence of load on smoke (and to a lesser extent, CO and HC) may be an indication of how that particular burner was adjusted, rather than a general measure of the capabilities of the boiler/burner combination. Burners frequently are adjusted to operate at higher excess air levels at low load than at the normal high load.

Influence of Fuel on Smoke Emissions

Notwithstanding the fact that this study has been the most extensive field investigation ever conducted of emissions from residential units and commercial boilers, there are relatively

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*These curves – for each boiler, fuel, and load – are presented in Appendix H as the Data Supplement Volume.

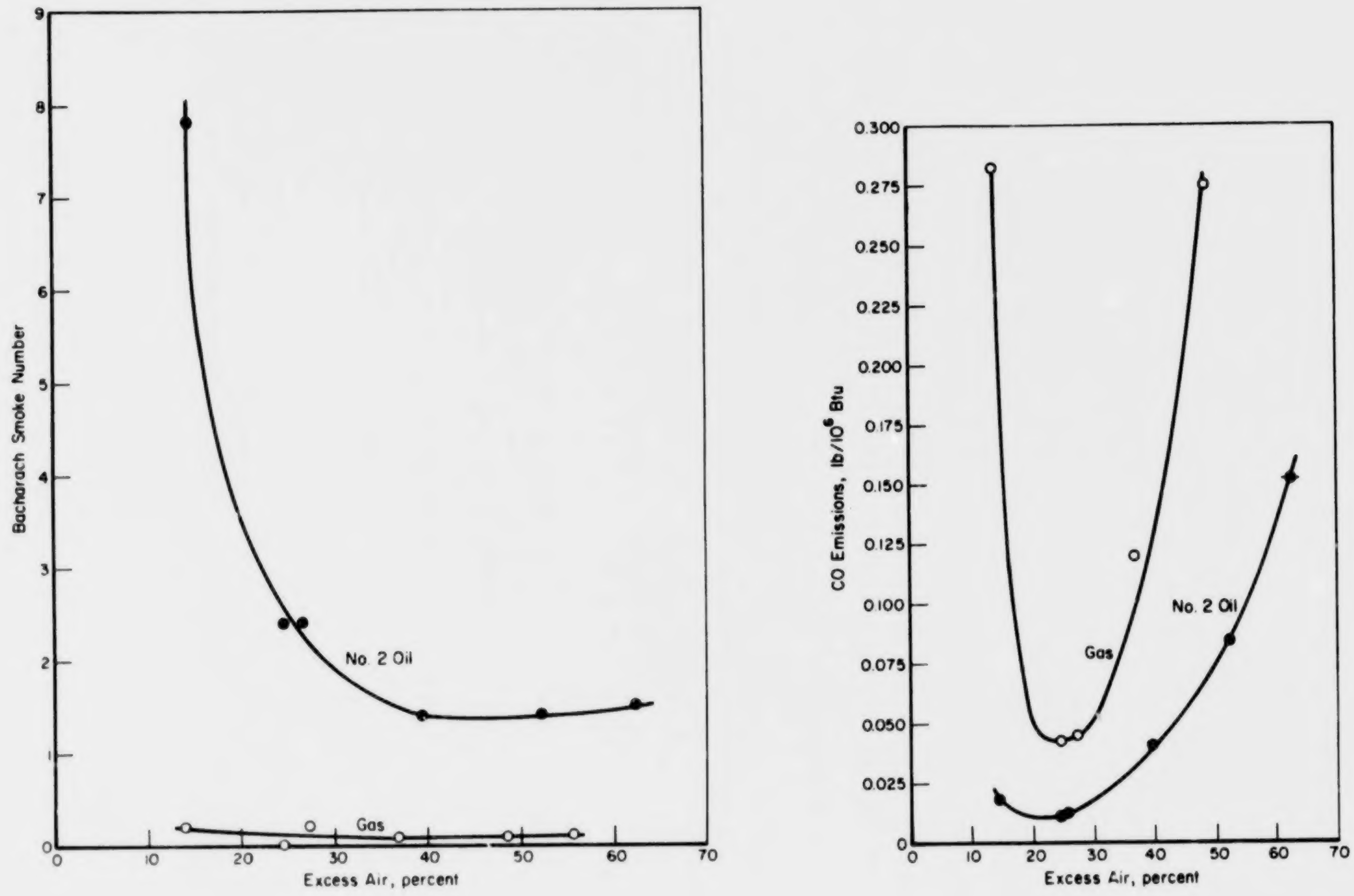

Figure III-17. Relation of Smoke and CO Emissions to Excess Air for Boiler C2001 at 80 Percent Load

40-bhp Cast Iron Boilers.

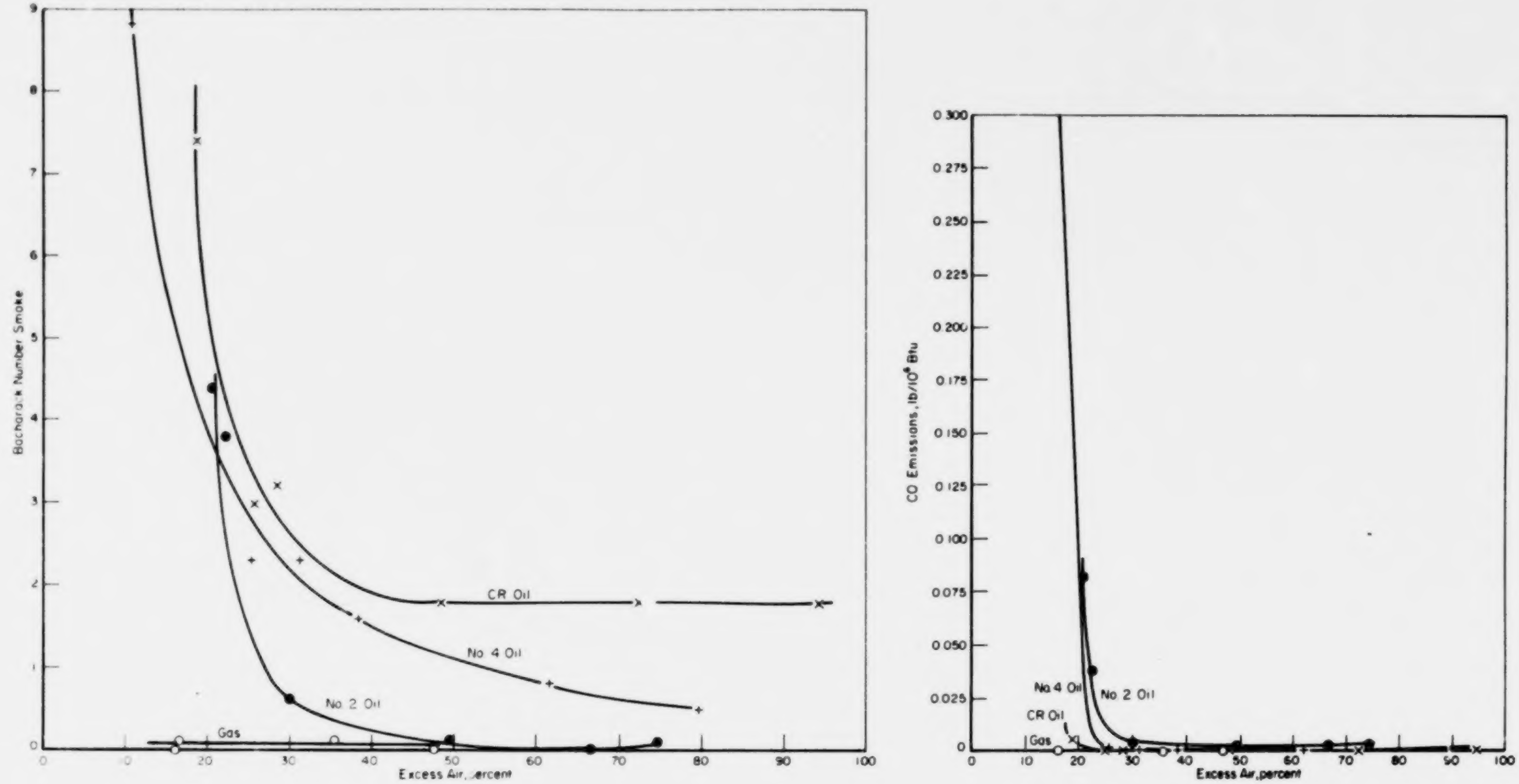

Figure III-18. Relation of Smoke and CO Emissions to Excess Air for Boiler C2002 at 80 Percent Load

90-bhp Cast Iron Boiler.

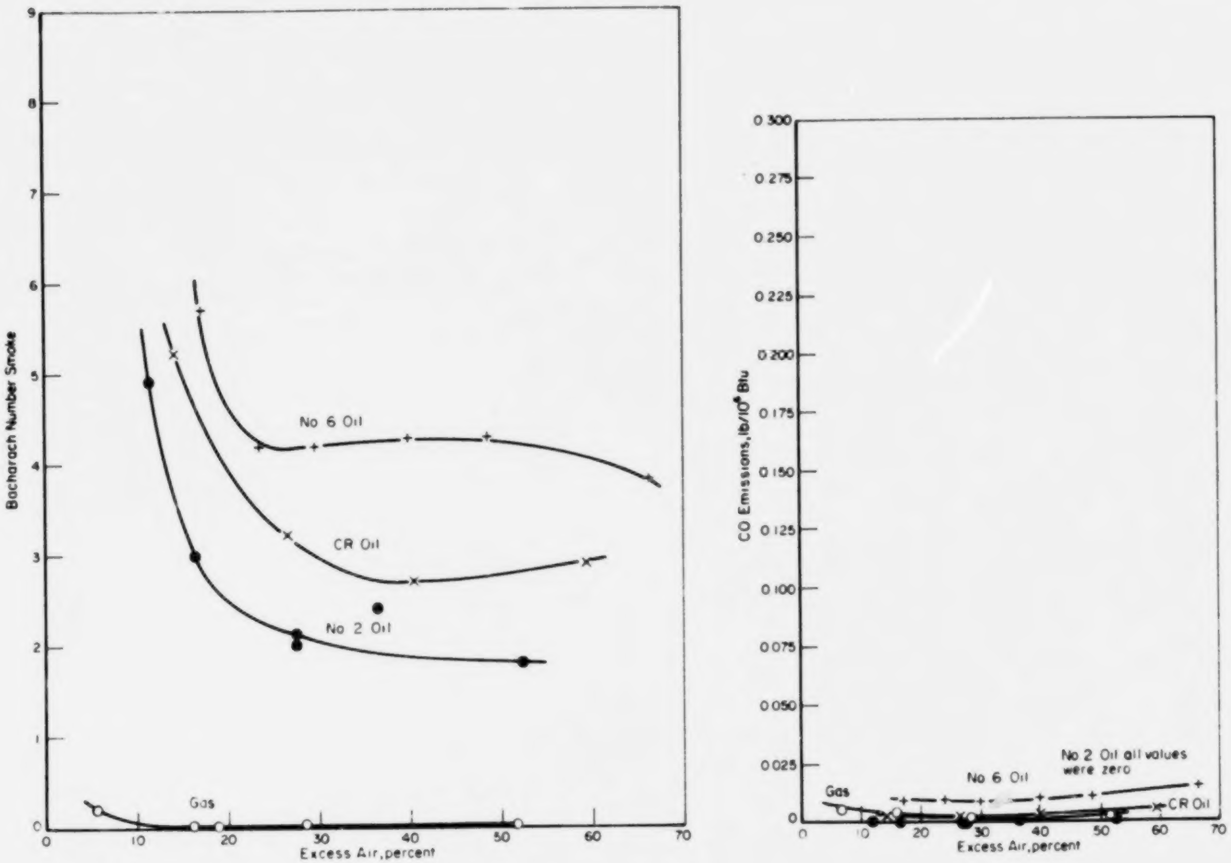

Figure III-19. Relation of Smoke and CO Emissions to Excess Air for Boiler C2003 at 80 Percent Load

300-bhp Scotch Boiler.

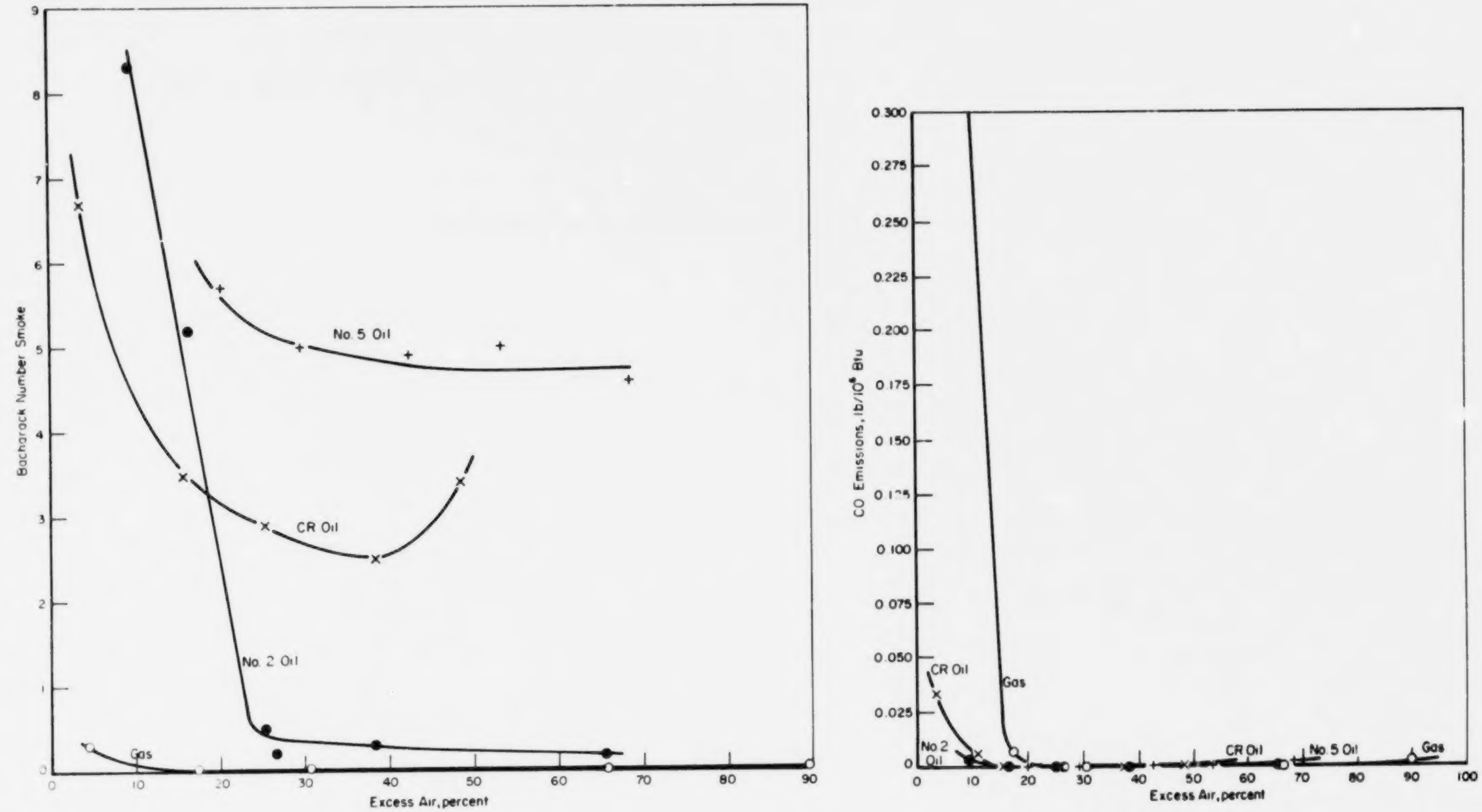

Figure III-20. Relation of Smoke and CO Emissions to Excess Air for Boiler C2004 at 80 Percent Load

80-bhp Firebox Boiler.

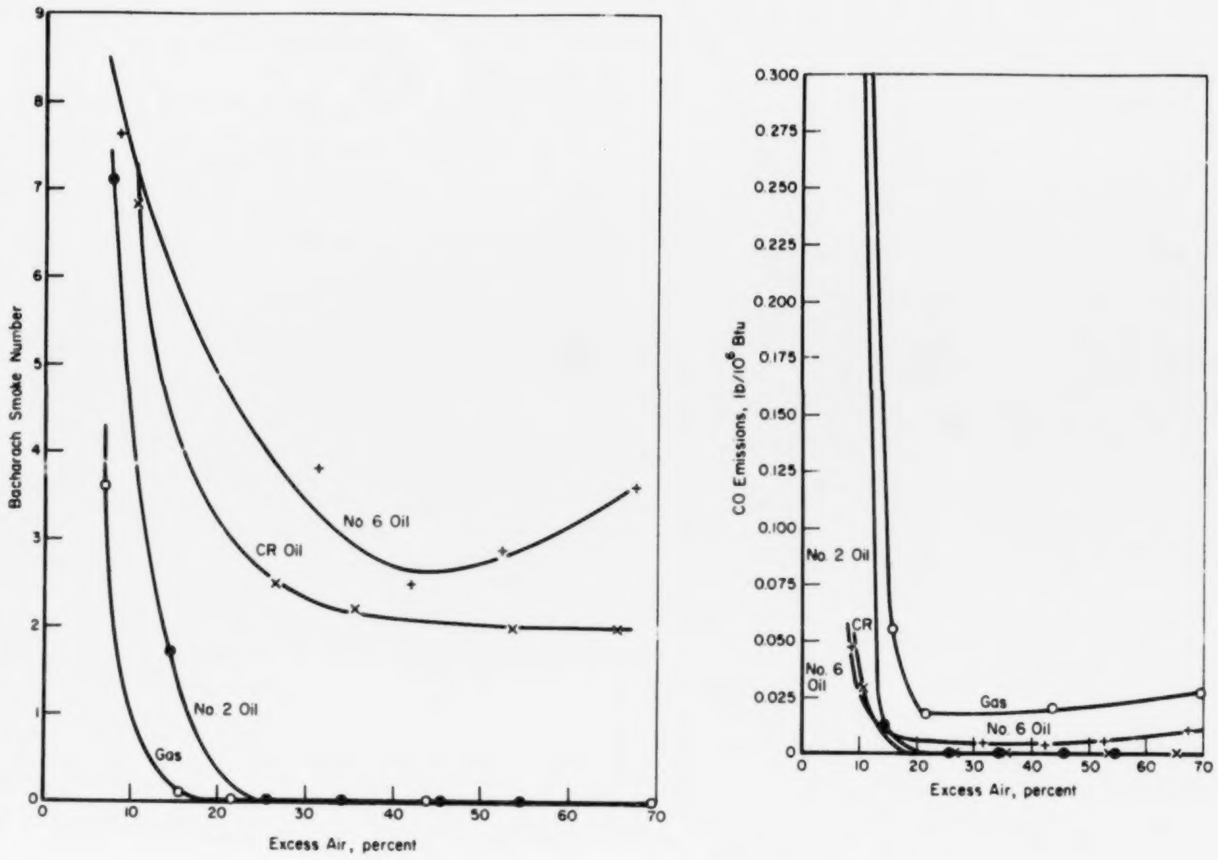

Figure III-21. **Relation of Smoke and CO Emissions to Excess Air for Boiler C2005 at 80 Percent Load**

100-bhp Scotch Boiler.

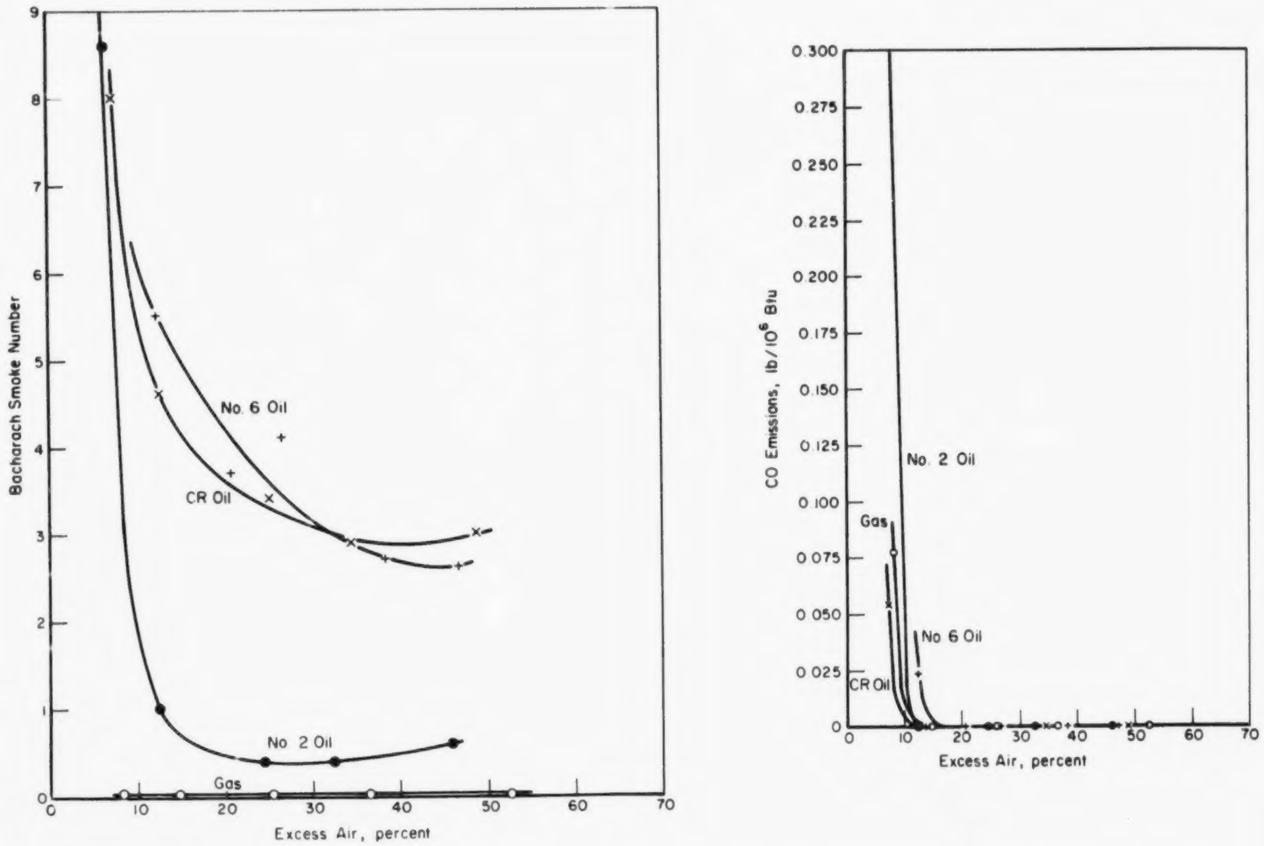

Figure III-22. **Relation of Smoke and CO Emissions to Excess Air for Boiler C2006 at 80 Percent Load**

600-bhp Watertube Boiler.

few data available from this program, considering the large number of variables that might influence emissions. However, examination of the relationship to emissions of the fuel variable considered most likely to correlate with emissions was valuable. It was decided that API gravity is probably the best readily available single property by which the combustion characteristics of fuel oils can be classified. Therefore, several trials were made at correlating emissions with API gravity of the fuels.

Figures III-23 and III-24 show relationships between Bacharach smoke number and API gravity. Figure III-23 summarizes data for all Phase I and II boilers for runs at the base-line condition. Figure III-24 shows the relationship separately for each Phase II boiler. Both figures reveal that smoke generated at the 80 percent load, 12 percent CO_2 base-line firing condition increased as the API gravity of the fuel decreased.

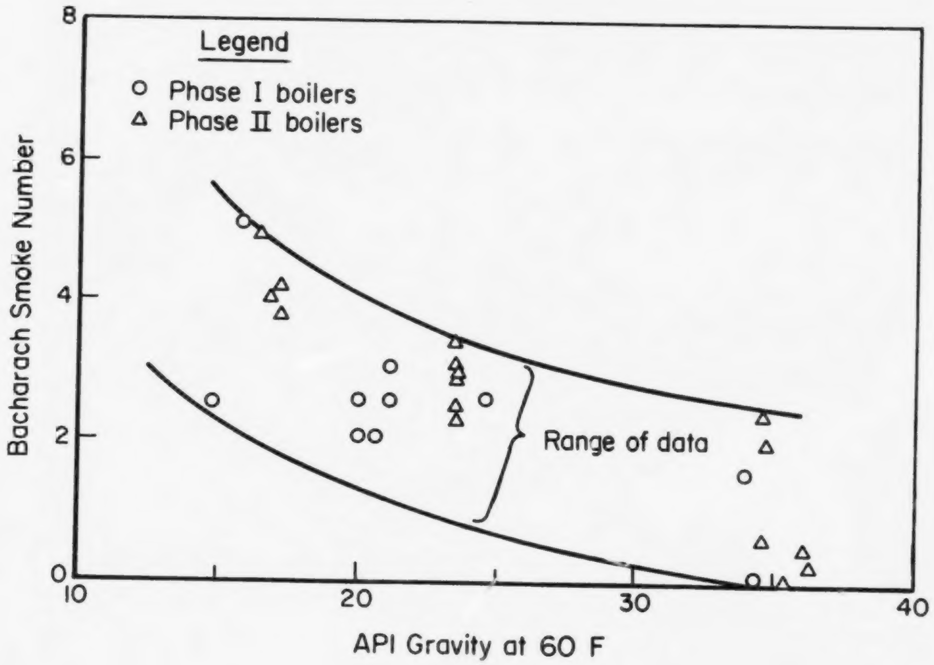

Figure III-23. Relation of Fuel Gravity and Smoke Number for the Commercial Boilers Operating at 80 Percent Load and 12 Percent CO_2

Phases I and II Boilers.

Figures III-17 through III-22 show that the heavier fuel oils generally tended to produce greater smoke over the entire range of CO_2 investigated.

All smoke spots obtained from firing the reference fuel, CR, were yellow in appearance. The coloration was not attributable to unburned fuel, but was assumed to result from compounds formed from trace metals in the fuel.

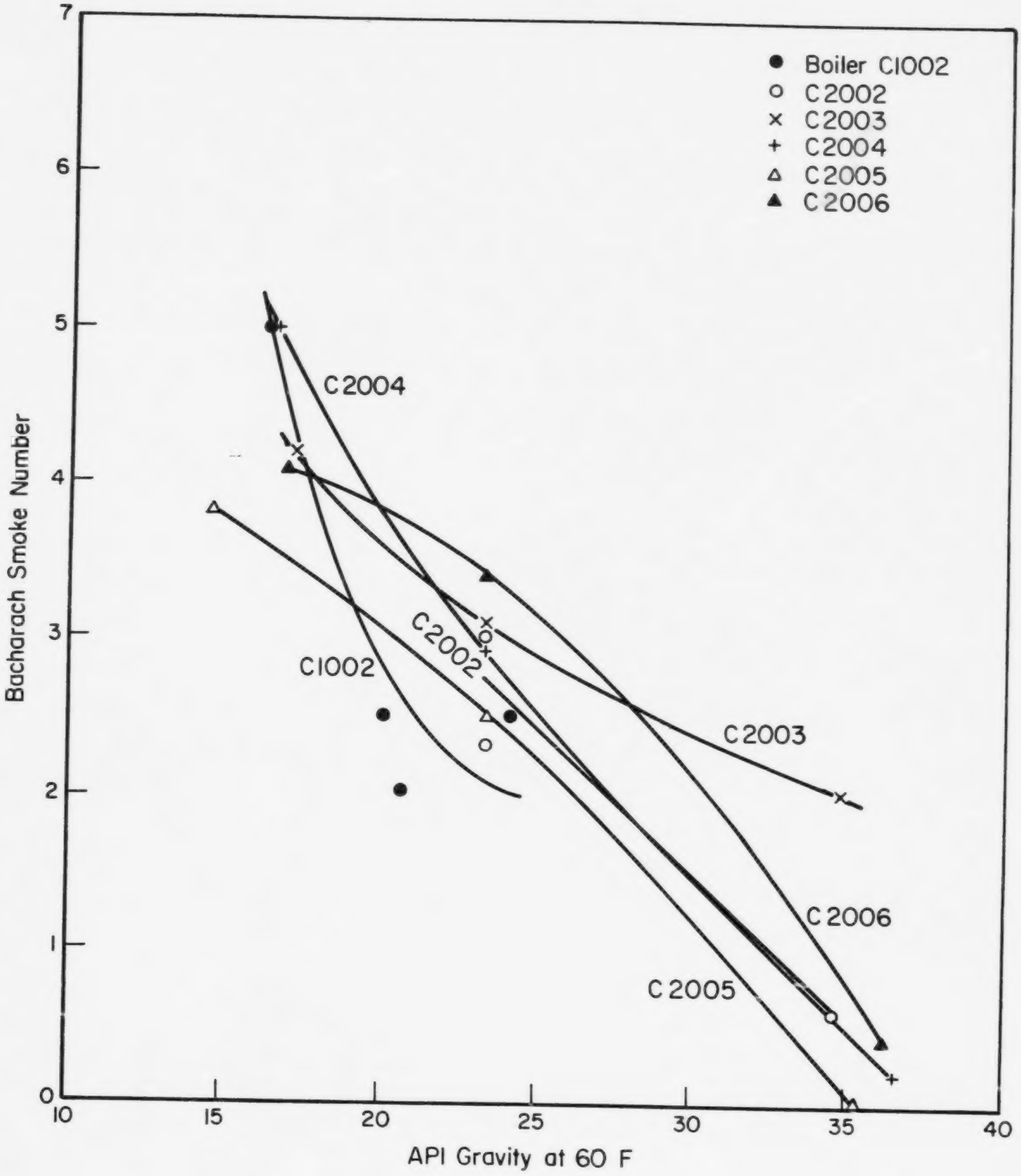

Figure III-24. Relation of Bacharach Smoke No. and API Gravity for Oil Firing of Phase II Commercial Boilers for 80 Percent Load and 12 Percent CO_2

Factors Influencing Particulate Emission

A regression analysis was used to determine the best equation relating filterable emissions to the same fuel and boiler characteristics as considered for the NO_x correlation (see page III-12). The equation that resulted was

Filterable particulate (lb/1000 gal) = 884.6 + 9.099 Carbon residue (percent. Ramsbottom) - 0.120 · Viscosity (SSU) - 10.88 · Carbon content (percent) + 1.77 · API gravity

This equation gave an 0.86 correlation with the filterable particulate data. Correlation coefficients with particulate emissions obtained when each variable was considered separately are as follows:

Variable	Correlation Coefficient (Absolute Value)
Carbon residue, Ramsbottom	0.68
Fuel nitrogen, N	0.62
$N^{1/2}$	0.57
Specific gravity	0.55
API gravity	0.55
Carbon content, C	0.52
Hydrogen content, H	0.44
$\frac{C}{N}$	0.43
$\frac{C}{H}$	0.40
$\frac{C}{H + N}$	0.33
Viscosity at firing temperature, SSU	0.25
Firing rate	0.21
Firing rate per unit combustion chamber volume	0.14
Combustion chamber volume	0.05

Figure III-25 shows the filterable particulate emissions plotted against carbon residue and the curve that correlated at the 0.68 level. As for the NO_x emissions, filterable particulate emissions correlated better with fuel characteristics than with boiler characteristics.

Figure III-26 shows the relationship of filterable and total particulate to API gravity for each of the Phase II boilers at 80 percent load and 12 percent CO_2. As might be expected, each Phase II boiler showed increasing particulate emissions for heavier fuels. However, the range of emissions obtained when firing fuels of similar gravities in different boilers was large. Thus, boiler and/or burner characteristics may have as much or more influence on emissions than fuel properties.

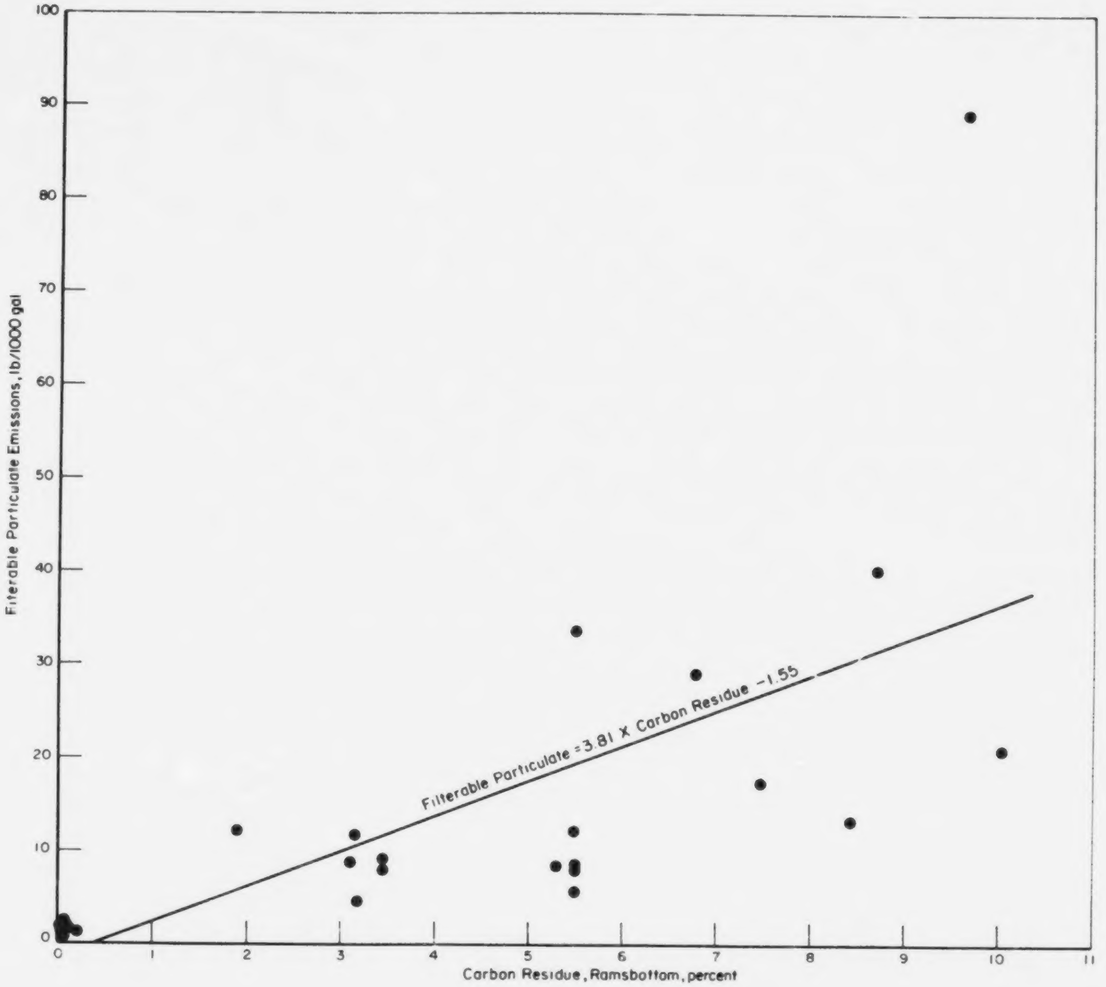

Figure III-25. Correlation of Filterable Particulate Emissions With Carbon Residue Particulate Emissions by Modified EPA Procedure.

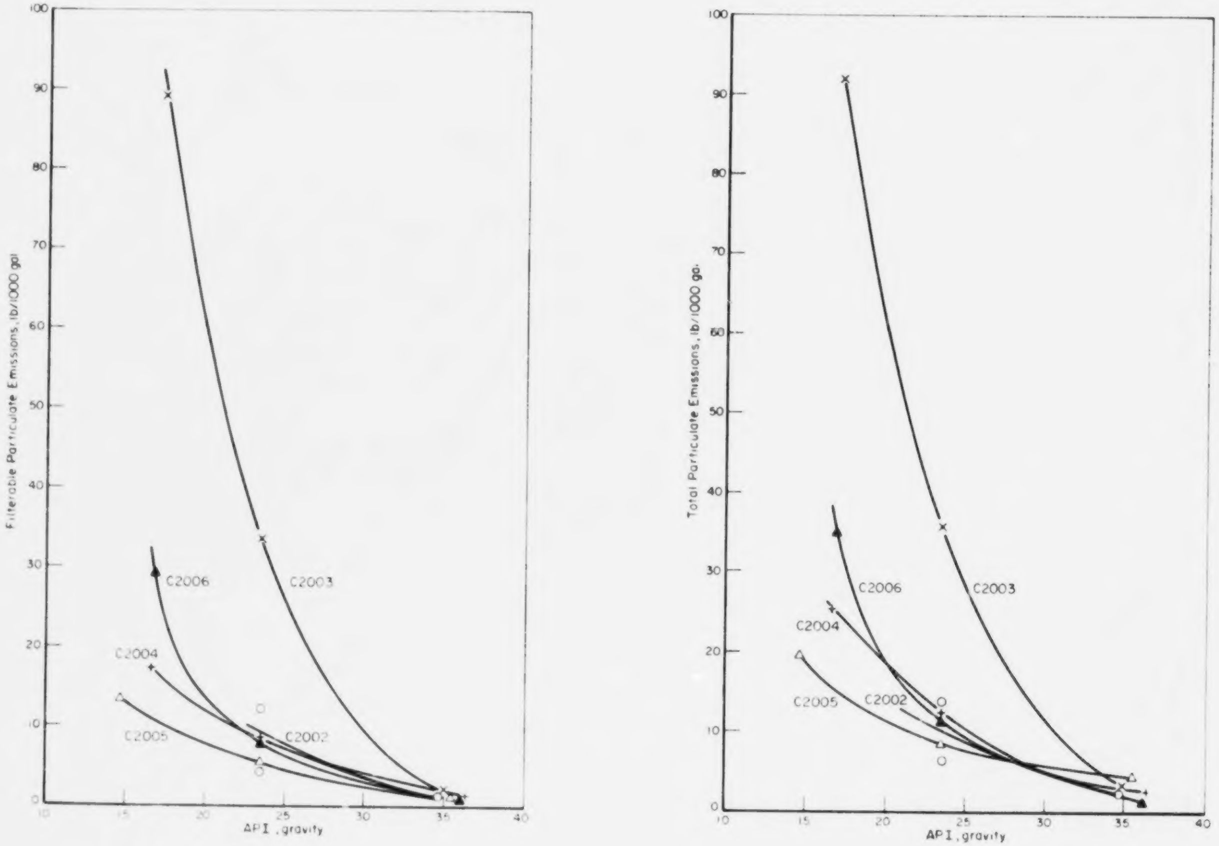

Figure III-26. Relation of Particulate Emissions to Fuel API Gravity for Base-Line Conditions

Particulate emissions by modified EPA procedure.

Relation of Particulate Emissions to Load. Figure III-27 shows the change in filterable particulate emissions with load for each Phase I and II boiler and fuel where data at two loads are available. In general, increasing load did not significantly affect filterable particulate emissions, except for firing of No. 6 fuel oil. For the four boilers fired with No. 6 fuel oil, emissions showed a substantial increase with increasing load. Particulate emissions increased from 0.15 to 1.3 lb/1000 gal for each 1 percent increase in load over the range for which data are available.

Trial Correlation of Smoke Versus Particulate Emissions

Figure III-28 shows the relationship of filterable particulate (as determined by the modified EPA procedures) to smoke number for each Phase II boiler at the base-line condition. It must be pointed out that the fuel varies for each point on each boiler curve. Hence, several variables are included in these plots and the relationship of particulate emissions to smoke should be examined further.

These data appear to provide a better correlation between smoke number and particulate for the commercial boilers than the residential unit data in that, for each boiler, particulate emissions increased with smoke number. This may relate to larger spread in particulate emissions for the commercial boilers or, more likely, to the fact that the particulate samples for the commercial boilers were taken under steady-state conditions, whereas the samples for residential units included start-up and shutdown during cyclic operation.

Particle Size Measurements

Emission samples were collected from Boilers C2005 and C2006 during operation with the low-sulfur reference fuel (CR) at 12.1 percent CO_2, 78 percent load and 12 percent CO_2, 80 percent load, respectively.

Procedure. Sampling was performed isokinetically at the center of each stack using the Battelle cascade impactor. The impactor classifies particles in the range of 0.25 – 16.0 microns into 7 size categories. For the sampling done for this study, a 5/8-inch-diameter sample probe about 20 inches in length (from probe tip to impactor inlet) was used. It had a 90 degree, 6-inch radius bend such that the probe tip pointed upstream. The impactor was operated horizontally and was heated to stack gas temperature (about 400 F) prior to probe insertion in the stack. Sampling at 12.5 liters per minute was initiated immediately on probe insertion into the stack. Sampling times for Boiler C2005 were 0.5, 1, 2, 5, or 10 minutes and for Boiler C2006 were 1 and 2 minutes. After sampling, the impactor slides were removed immediately and returned to the laboratory for weighing.

The impactor slides were covered with a disk of silver membrane material so that the entire glass slide did not have to be weighed. The possibility of weight change of the silver membrane filters by reaction during the sampling operation was calibrated by baseline measurements made with an all-glass filter placed in-line ahead of the impactor. In these calibration runs no particles were collected in the impactor and the small weight changes of the silver substrates provided corrections for use during particle size measurements.

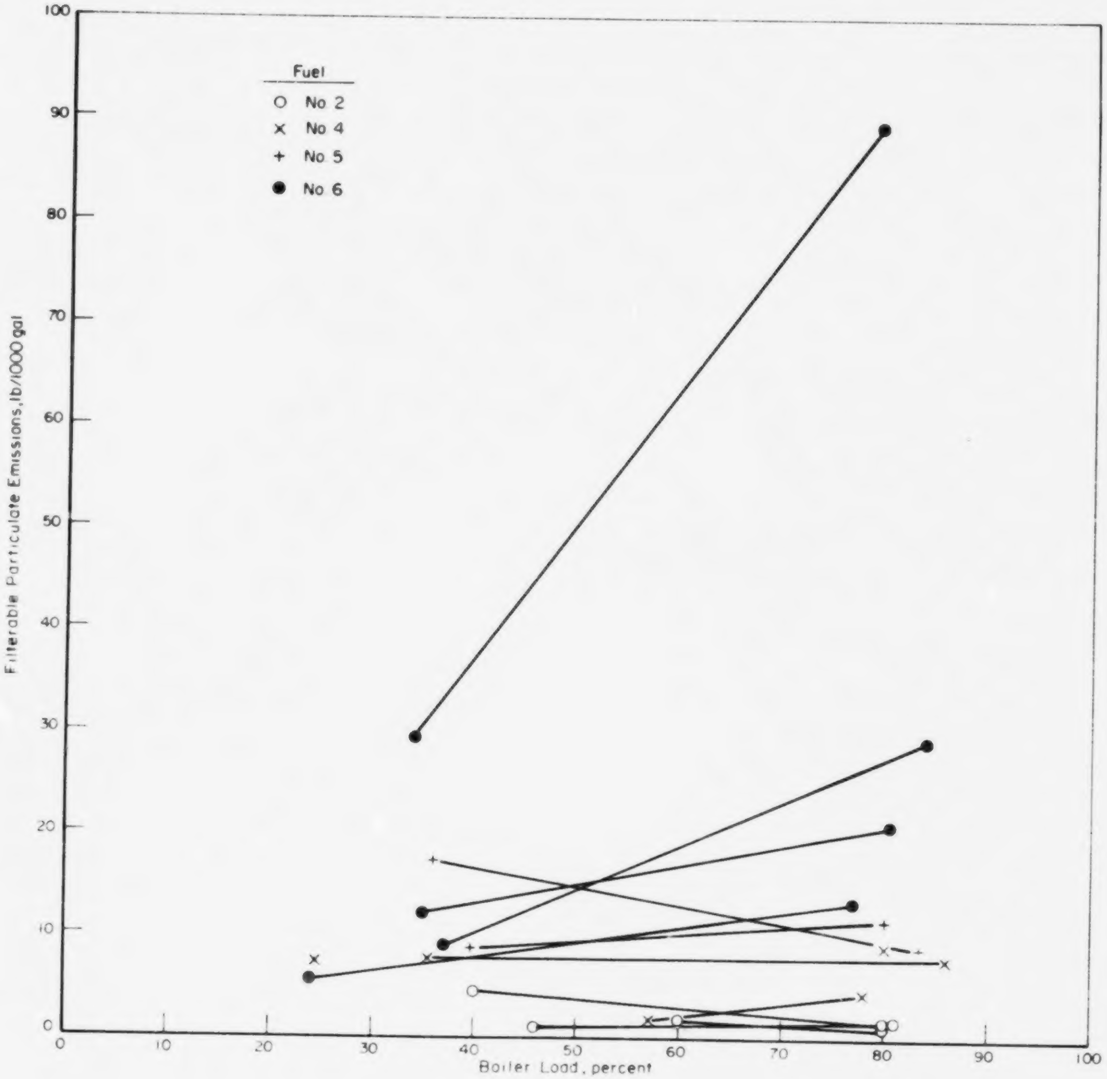

Figure III-27. Effect of Load on Filterable Particulate Emissions From Phases I and II Commercial Boilers

Particulate Emissions by Modified EPA Procedure.

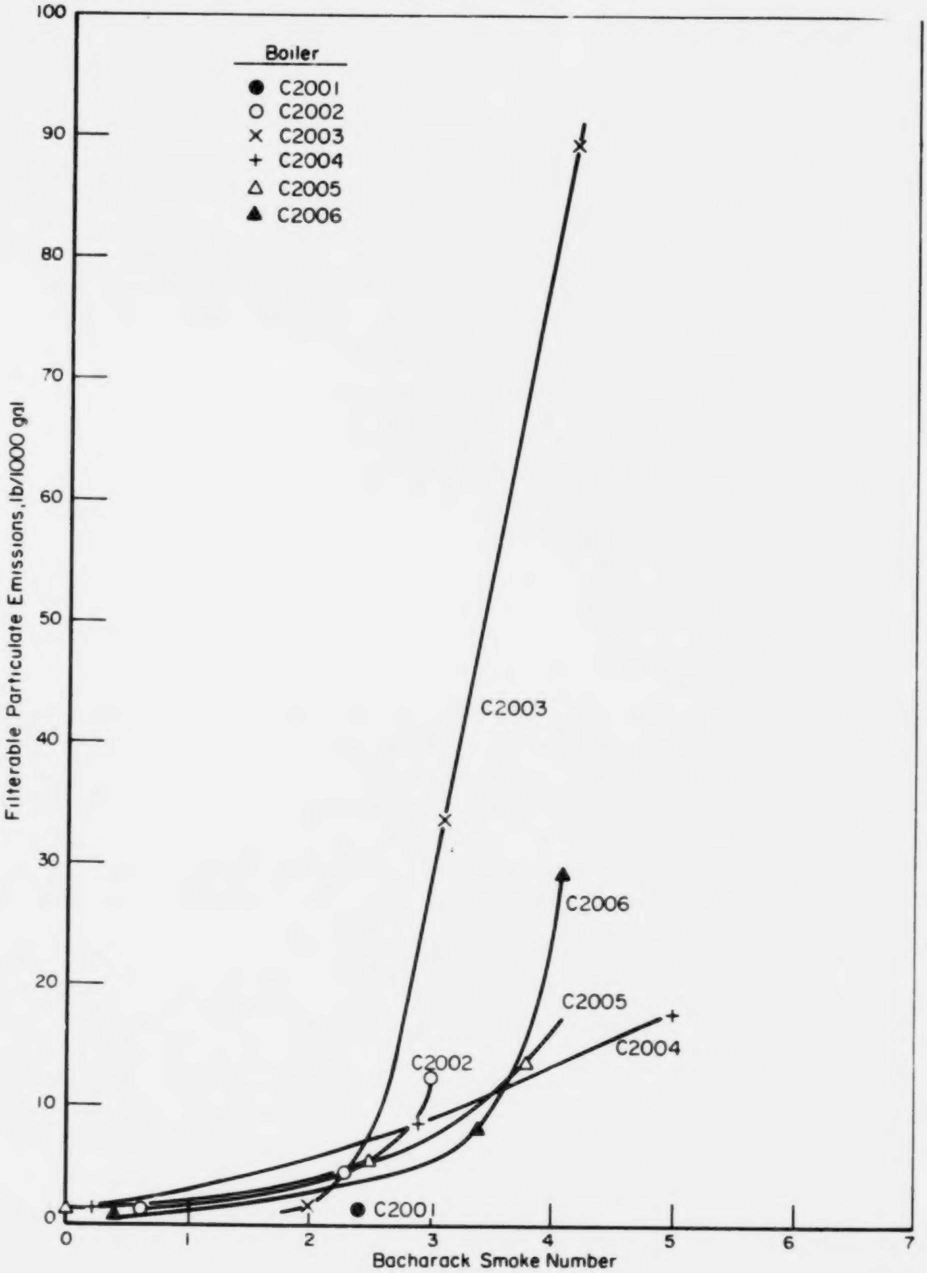

Figure III-28. Relation of Filterable Particulate and Smoke Numbers for Commercial Boilers

Particulate Emissions by Modified EPA Procedure.

Results. The weights of particles collected on each stage provided the basis for size distribution determinations, and the total particulate weight collected in the impactor provided a measure of the particulate emission rate. The small quantities of particulate collected indicated that sampling times of five minutes or more were required for reliable results. This situation resulted in discarding the 1 and 2-minute samples for Boiler C2005 and both samples (1 and 2-minute) taken from Boiler C2006.

The results for particule size distributions measured for the 5 and 10-minute sampling periods for Boiler C2005 are shown in Figure III-29. It can be seen that the agreement for the two samples is reasonably good with the mass mean size of the particulate emissions estimated to be about 0.5 micron for both. As the particle masses collected were near the lower limit of sensitivity for the balance, these data must be considered as approximate. Improved weighing techniques based on the experience gained in achieving these approximate results would be likely to produce data in which more confidence could be placed.

The total weight of particulate collected in the impactor was used to estimate the mass concentration of particles in the effluent stack gas. On this basis, the particulate loadings for Boiler C2005 were calculated to be 38.4 and 43.1 mg/sm^3 for the 5 and 10-minute sampling periods, respectively. These compare reasonably well with the emission concentration of 44.6 mg/sm^3 as determined independently with the EPA sampling procedures.

EMISSION FACTORS

Emission factors published by EPA[3] do not provide discrimination relative to fuel properties. Generally, EPA fuel categories are limited to "distillate oil" and "residual oil" as classes. Many industry observers believe that a finer discrimination of fuel properties needs to be considered. For example, the present practice would include in the same "residual" category both No. 6 fuel oil with 3 percent sulfur (API gravity about 15) and the newer low-sulfur heavy oils being marketed on the East Coast (API gravity about 24). However, it is well known that these low-sulfur fuels are much easier to fire (about like No. 4 fuel oil) and generally give much cleaner combustion.

Emission Factors Related to API Gravity

In recognition of the need for finer discrimination of fuel oils when considering their emission potential, a correlation was made of emissions relative to API gravity of fuels. Figures III-30 to III-33 show Phase I and II boiler-emission data at the base-line conditions (80 percent load and 12 percent CO_2) plotted against fuel gravity for CO, HC, filterable particulate, and total particulate emissions. These figures also show the "best curve" that could be fit to these data by a polynominal regression analysis that utilizes least square procedures.* It is suggested that, although considerable scatter exists in the data, emission factors based on the API gravity and the curves shown in Figures III-30 to III-33 give the best available estimate of likely emissions from any one boiler firing any one fuel.

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*The curves were limited to second-order polynominals to avoid negative values and peaks.

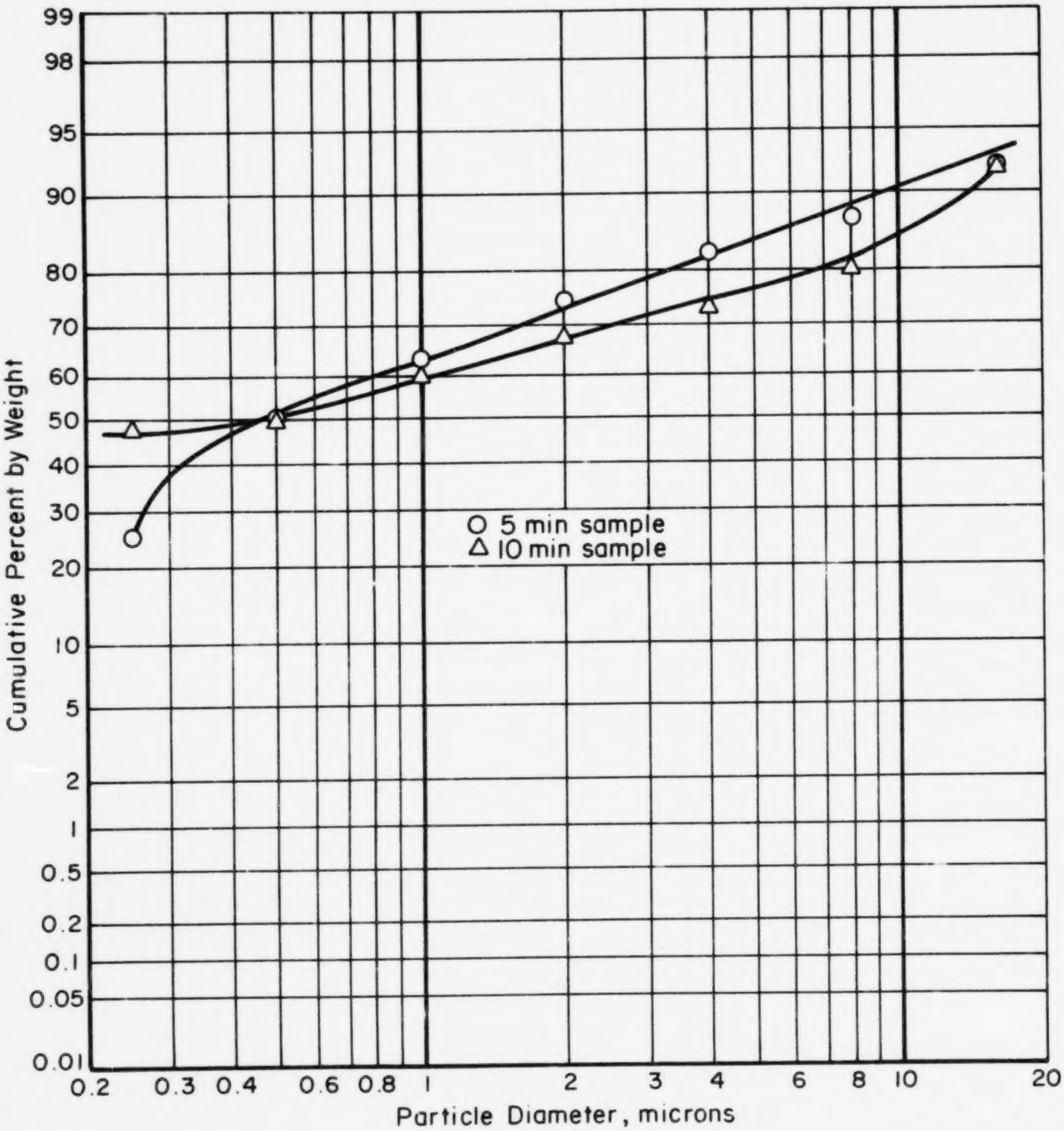

Figure III-29. Particle Size Distributions for Boiler C2005 Firing the Commercial Reference Fuel

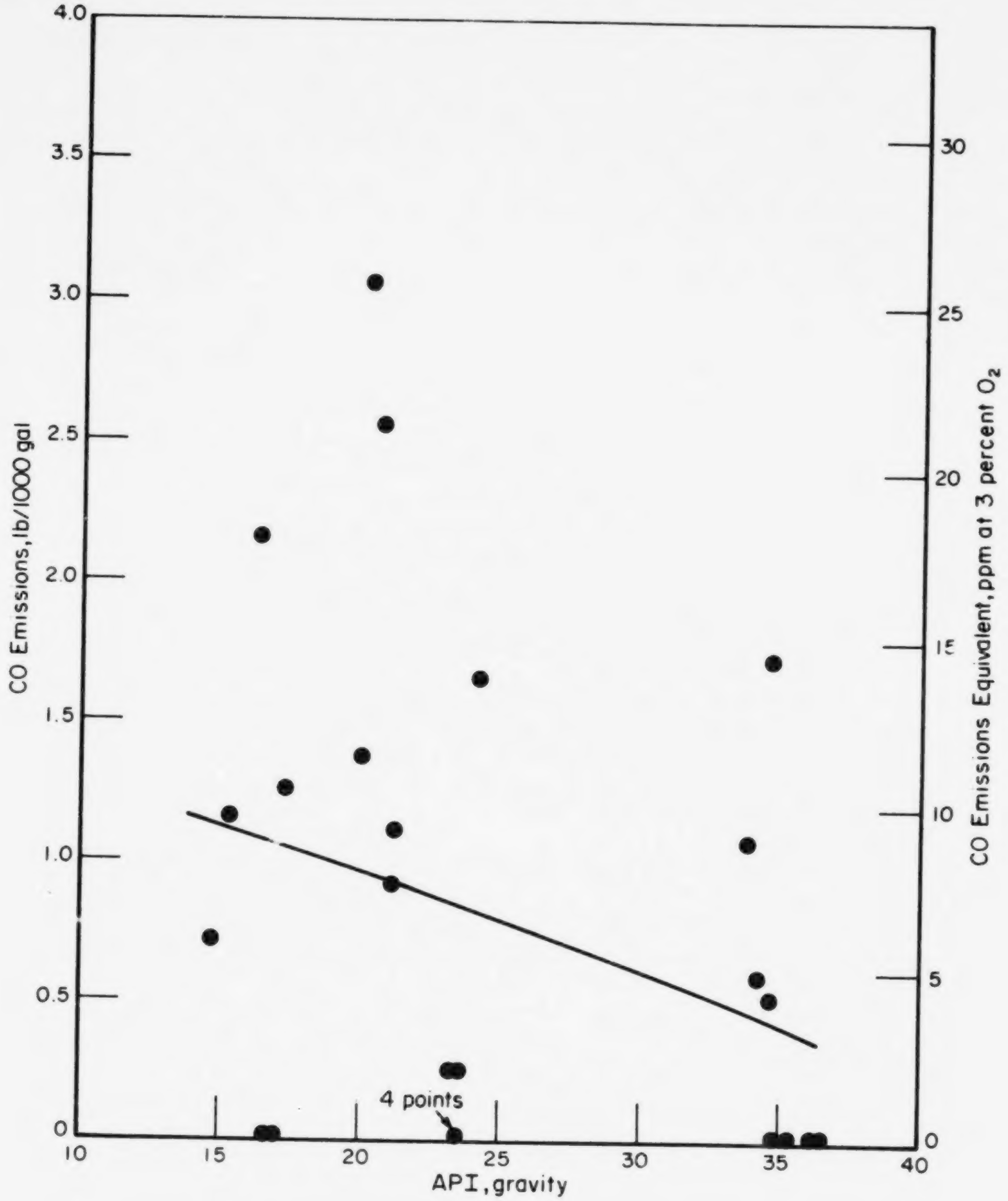

Figure III-30. Relation of CO Emissions to API Gravity for Commercial Boilers

Equation for curve: $CO = 1.572 - 0.0278\ (API) - 0.00015\ (API)^2$.

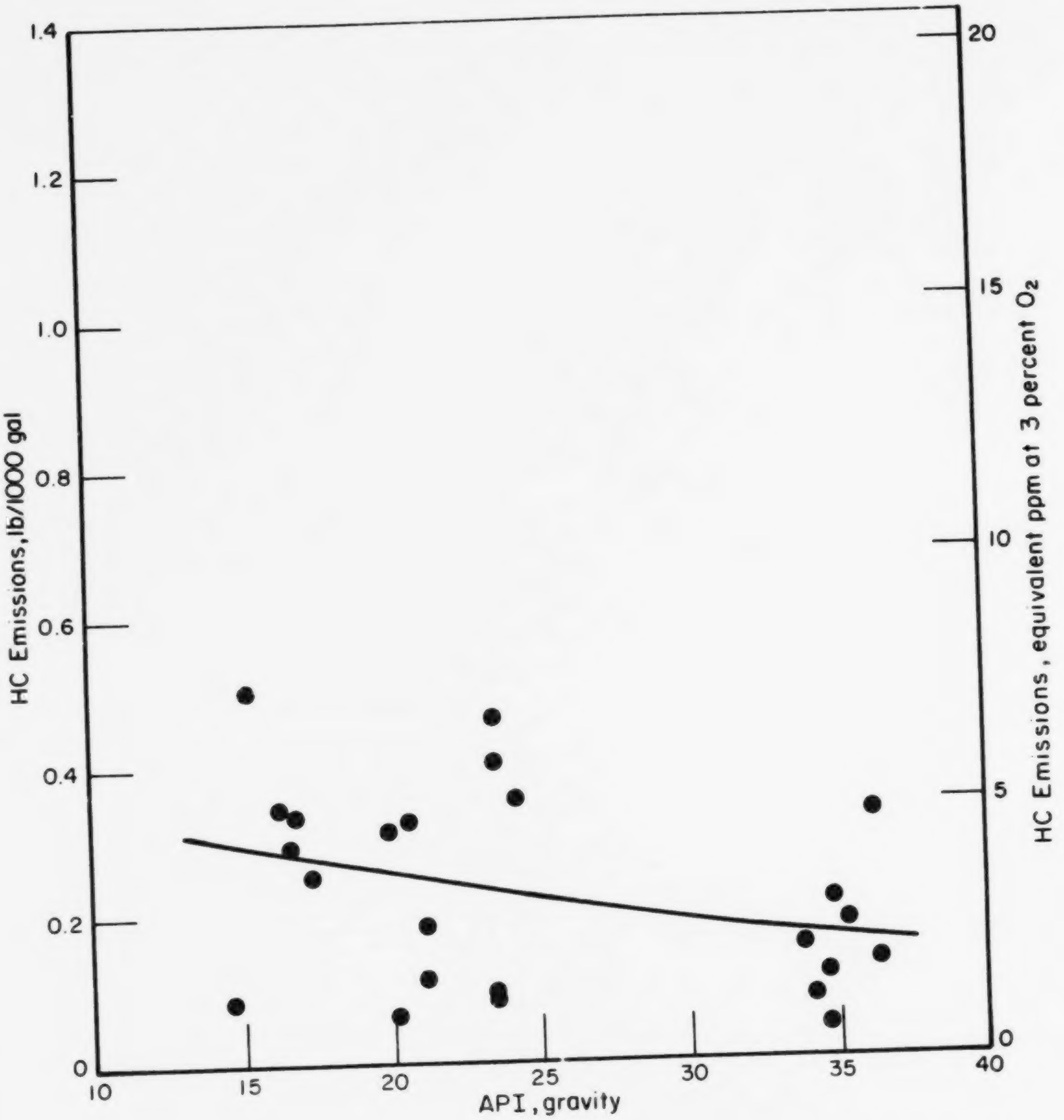

Figure III-31. Relation of HC Emissions to API Gravity for Commercial Boilers

Equation for curve: $HC = 0.439 - 0.0110\ (API) + 0.00009\ (API)^2$.

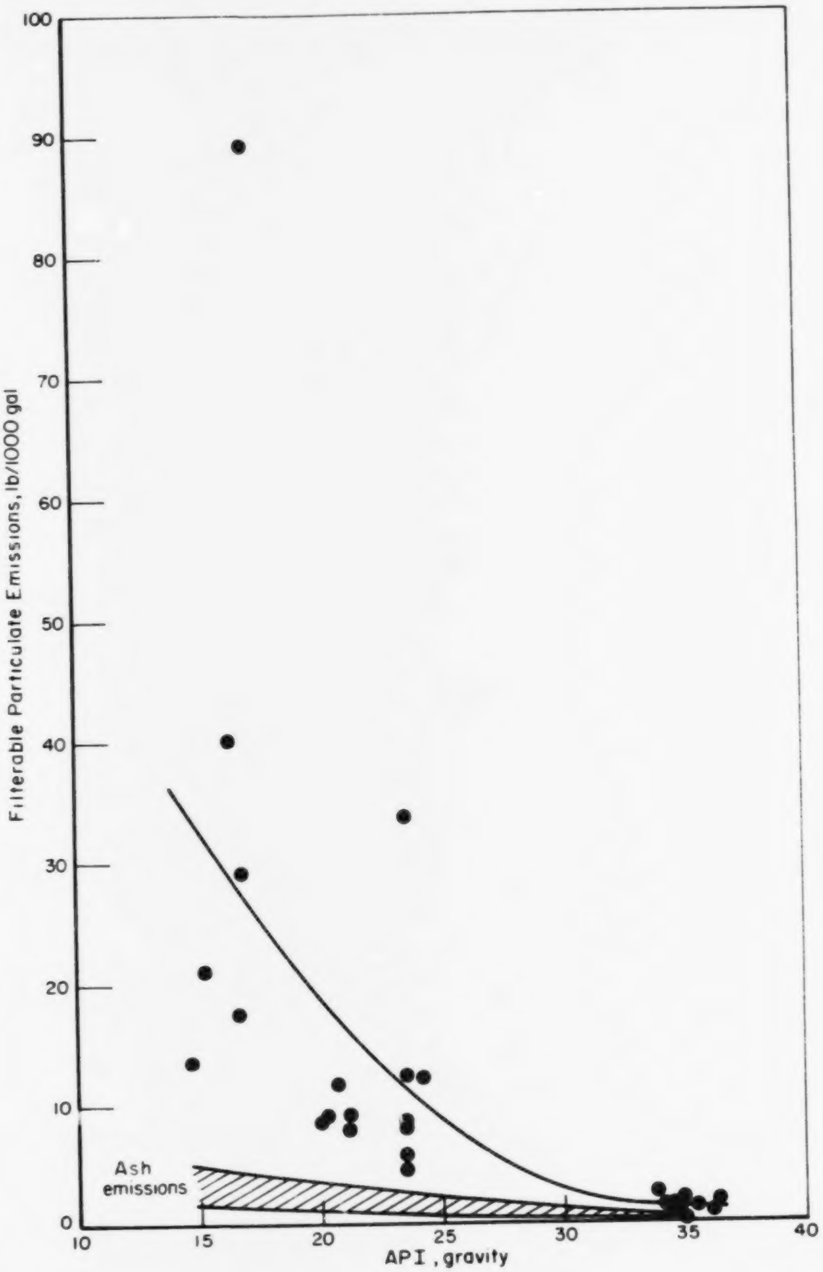

Figure III-32. **Relation of Filterable Particulate Emissions (by Modified EPA Procedure) to API Gravity for Commercial Boilers**

Equation for curve = Filterable Particulate = 100.5 - 5.75 (API) + 0.0832 $(API)^2$. This curve does not apply at API gravities above 34.5.

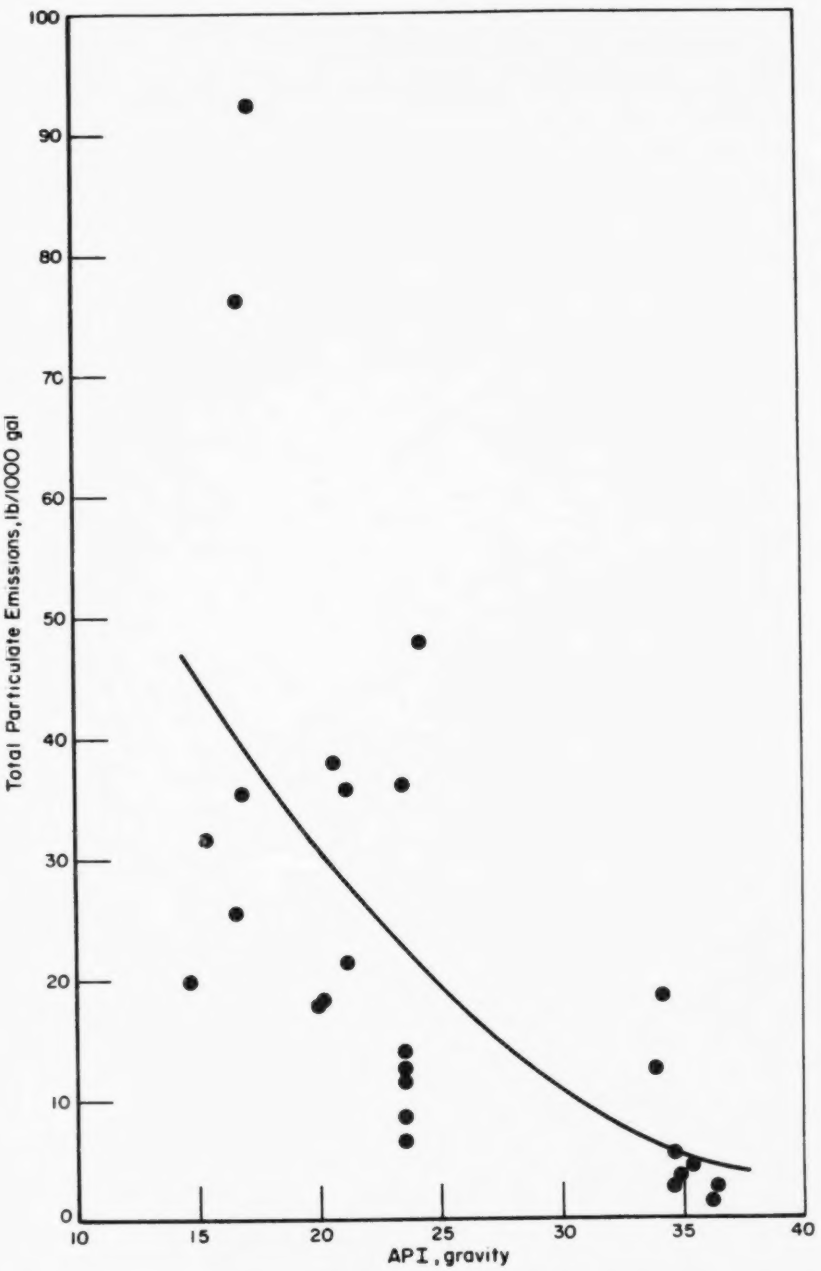

Figure III-33. **Relation of Total Particulate Emissions (by Modified EPA Procedure) to API Gravity for Commercial Boilers**

Equation for curve: Total Particulate = 106.2 - 4.96 (API) + 0.0597 $(API)^2$.

Suggested Emission Factors for Commercial Boilers

The curves presented in Figures III-30 through III-33 can form the basis for recommended emission factors to be used in emission inventories, where an average emission level is needed for developing total emissions for oil-fired commercial boilers based on fuel usage.

To establish values for API gravity which are typical of different grades, results of an informal survey of fuel specialists on the API Task Force were combined with average values for fuels encountered in this field investigation. The resulting values are as follows:

Fuel Grade		Typical API Gravity, degrees at 60 F
Distillate oil	No. 2	34
Conventional resid.	No. 4	22
"	No. 5	17
"	No. 6	14
New low-sulfur residual (1.0% S)		23

Oil-Fired Boilers. Table III-6 shows the resulting emission factors which are suggested for use in emission inventories applying to oil-fired commercial boilers. These factors are based on emission measurements of 27 combinations of boilers and fuels, a fairly broad cross section of conditions encountered in the field. They should be updated as more comprehensive data become available, particularly to keep up with trends in fuels.

Gas-Fired Boilers. Table III-7 shows average emission factors obtained from firing seven commercial boilers with natural gas.

Emission Factor for NO_x. Assuming that the single variable relating best to NO_x emissions was fuel nitrogen, it was determined that NO_x emissions should not be expressed in terms of API gravity. (However, for many fuel oils there is a fairly strong relationship between fuel nitrogen and API gravity.) Hence, using the equation relating NO_x to fuel nitrogen described earlier (Page III-14), NO_x emission factors were calculated for fuels of various API gravities. These results are included in Table III-6.

When fuel nitrogen data are lacking, the following values are suggested:

Fuel	Fuel Nitrogen, percent
No. 2	0.01
No. 4	0.2
No. 5	0.3
No. 6	0.4
LSR	0.2

Table III-6. Suggested Emission Factors for Oil-Fired Commercial Boilers[a]

	Emission Factors, lb/1000 gal[b]				
Fuel Grade[a]	CO	HC	NO_x[c]	SO_2[d]	Filterable Particulate
Suggested Emission Factors From This Study[e]					
No. 2	0.45	0.17	$20 + 78\ N^{0.6}$	142 S	1.2
No. 4	0.89	0.24	$20 + 85\ N^{0.6}$	154 S	14.0
No. 5	1.06	0.28	$20 + 87\ N^{0.6}$	159 S	27.0
No. 6	1.15	0.30	$20 + 89\ N^{0.6}$	162 S	36.0
LSR[f]	0.85	0.23	$20 + 84\ N^{0.6}$	153 S	12.0
EPA Published Emission Factors[3]					
Distillate Oil No. 2	0.20	3.00	40 to 80	142 S	15.0
Residual Oil Nos. 4,5,6	0.20	3.00	40 to 80	157 S	23.0

[a] These values are based on average emission data for the identified fuel grades having typical API gravity as follows: 34 degrees API for No. 2, 22 for No. 4, 17 for No. 5, 14 for No. 6, and 23 for LSR. Where actual API gravity is known, interpolated values should be used.

[b] To convert these values to emission factors in lb/10^6 Btu, multiply values shown by 0.0069. (The actual multiplier varies slightly with fuel grade, being about 0.0071 for No. 2 fuel oil and 0.0066 for No. 6 fuel oil.)

[c] N = multiplication factor equal to percent nitrogen in fuel.

[d] S = multiplication factor equal to percent sulfur in fuel. These emission factors were determined by calculation. Measured SO_2 emission factors were within 10 percent of these values.

[e] Based on firing at 80 percent load and 12 percent CO_2.

[f] LSR: low-sulfur residual oil (1.0 percent S).

Table III-7. Suggested Emission Factors for Gas-Fired Commercial Boilers

Emission Factors, lb/10^6 cu ft[a]				
CO	HC	NO_x	SO_2	Filterable Particulate
Suggested Emission Factors From This Study[b]				
17.7	3.7	103.	Nil	5.6
EPA Published Emission Factors[3]				
20	8	100	0.6	19

[a] To convert these values to emission factors in lb/10^6 Btu, multiply these values by 0.00098.

[b] Based on firing at 80 percent load and 10 percent CO_2.

APPENDICES

A. BACKGROUND DATA ON RESIDENTIAL OIL-FIRED EQUIPMENT POPULATION

B. BACKGROUND DATA ON COMMERCIAL-INDUSTRIAL BOILER POPULATION

C. FUEL ANALYSES

D. DETAILS OF FIELD PROCEDURES

E. SAMPLING AND ANALYTICAL PROCEDURES FOR GASEOUS EMISSIONS

F. SAMPLING AND ANALYTICAL PROCEDURES FOR PARTICULATE AND SMOKE AND DETAILED PARTICULATE DATA

G.* DATA FOR RESIDENTIAL UNITS

H.* DATA FOR COMMERCIAL BOILERS

I.* CALCULATED EMISSION FACTORS FOR RESIDENTIAL UNITS

J.* CALCULATED EMISSION FACTORS FOR COMMERCIAL BOILERS

K. DETAILS OF EMISSION-FACTOR CALCULATIONS AND CONVERSION FACTORS

L. ERRATA TO PHASE I REPORT

M. REFERENCES

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*These appendices appear in the Data Supplement Volume which is available as a separate report.

APPENDIX A

BACKGROUND DATA ON RESIDENTIAL OIL-FIRED EQUIPMENT POPULATION

This appendix presents information on the current field population of oil-fired residential heating equipment in the United States by important characteristics, including firing rate, burner and heating system type, and age of burner and heating system.

RESIDENTIAL OIL-BURNER EQUIPMENT SURVEY

In the selection of residential units for this investigation, pertinent historical data were reviewed, including information compiled previously by *Fueloil & Oil Heat* magazine. To obtain more comprehensive information not previously recorded in the industry, a questionnaire was submitted to a large number of oil-burner service organizations through the statistical editor of *Fueloil & Oil Heat*. The same questionnaire also was submitted directly to the members of the API SS-5 Task Force and to a number of servicing companies in major cities. The pertinent portion of the questionnaire is reproduced as Table A-1.

Profile of Residential Oilheating Equipment Population

Tables A-2 through A-9 present information on the profile of oilheating equipment by type, age, and geographic distribution. The information was compiled and later published by *Fueloil & Oil Heat*[4].

The summary is organized in tables as follows:

Table A-2	Firing Rates of Oil Burners in Use
Table A-3	Oil Burners in Use, by Type
Table A-4	Average Age of Oil Burners in Use, by Type
Table A-5	Types of Central Oilheating in Use, by System Type
Table A-6	Average Age of Central Oilheating Equipment in Use, by System Type
Table A-7	Combustion Chambers of Oil Burners in Use, by Type
Table A-8	Oil Burners With Solenoid Valves

A number of general observations and trends in residential oilheating equipment that can be noted from these data include the following:

- Smaller size burners, with firing rates of 1.35 gph and below, make up the majority (about 70 percent) of residential units.
- Gun burners (with conventional, Shell, or flame-retention heads) represent a large majority of burners (about 84 percent).

- High-turbulence combustion leads (Shell and flame retention) represent less than 20 percent of all gun burners.
- The average age of all oil burners is slightly over 12 years, about the same as for gun burners with conventional combustion heads. Average age of burners with high-turbulence combustion heads is only about 6 years, while other types of burners (low-pressure, rotary, and vaporizing units) average nearly 17 years.
- Warm-air furnace and hydronic systems (hot water and steam) are about equal in number.
- In spite of the increased popularity of ceramic fiber combustion chambers in recent years, refractory brick combustion chambers still outnumber the ceramic fiber chambers by about four to one.

These findings are familiar qualitatively to those of long-time observers of the oilheating industry; however, the statistics contained in this appendix provide more quantitative information than available previously.

Residential Unit Selection for Phase II

Due to delays in receiving replies to the questionnaire, this information was not complete in time for planning the details of the Phase II residential equipment investigation. Thus, to keep this program on schedule it was necessary to rely on the previously published data to select units for Phase II of this program, as outlined in Chapter II.

The composition of the field sample, chosen prior to the comprehensive survey, is compared in Chapter II to this profile of the total field population. The mix of units chosen for the combined program of Phases I and II was generally representative of the total U.S. population of oil-fired residential equipment.

Table A-1. Sample Questionnaire

Battelle is doing some work for API and the Government on emissions of residential oilburners, and have asked your help on sizes and types of equipment in the field. Please give us your best estimates or guesses about the burners on your customer list.

What **percent** of your residential No. 2 burners are fired at less than 1.0 gph ______%; 1.0 to 1.35 gph ______%; 1.36 to 1.65 gph ______%; 1.60 to 2.0 ______%; 2.01 to 3.0 gph ______%; over 3.1 gph ______%

To further profile these existing burners, please fill in as much of the following data as possible:

	Less than 1.0 gph	1.0 to 3.0 gph	Average Age	
High Pressure*				
Conventional combustion head	______%	______%	______	years
Shell head	______	______	______	
Flame retention head	______	______	______	
Low Pressure**	______	______	______	
Rotary Wall Flame	______	______	______	
Vaporizing	______	______	______	
	100%	100%		

*Pressure atomizing (100 psi or greater).

**Air atomizing.

What percent of your customers have furnaces? ______% What percent have gravity hot water? ______% Have forced hot water with a tankless coil? ______% Forced hot water without tankless coil? ______% Have steam heat with tankless coil? ______%; steam without tankless coil? ______%

What would you guess would be the average age of your customers' furnaces? ______ years. What is the average age of your customers' boilers? ______years. What percent of your customers have space heaters? ______ %

Table A-2. Firing Rates of Oil Burners in Use[4]

	Firing Rate, gph					
	<1.0	1.0 to 1.35	1.36 to 1.65	1.66 to 2.0	2.01 to 3.0	Over 3.0
	Percent of Total					
New England	19.6	43.9	12.8	8.9	7.0	7.8
Mid-Atlantic	24.3	39.7	17.8	8.6	5.7	3.9
South Atlantic	51.8	29.8	9.3	5.7	1.6	1.8
Midwest	44.6	27.1	12.8	8.8	4.4	2.3
West	75.4	14.2	5.9	3.3	0.9	0.3
All Sections	34.6	34.7	13.9	8.0	4.9	3.9

Table A-3. Oil Burners in Use by Type[13]

	High Pressure					
	Conventional	Shell Head	Retention Head	Low Pressure	Rotary	Vaporizing
	Percent of Total					
	Less Than 1.0 gph					
New England	44.9	7.2	14.7	26.4	5.8	1.0
Mid-Atlantic	66.3	8.4	3.8	10.6	8.5	2.4
South Atlantic	74.8	1.9	13.0	0.8	0.1	9.4
Midwest	63.0	9.4	13.1	5.6	8.6	0.3
West	80.3	0.6	5.2	8.1	0.5	5.3
All Sections	63.1	7.2	9.1	11.5	6.6	2.5
	1.0 to 3.0 gph					
New England	61.4	7.9	13.6	9.0	7.6	0.5
Mid-Atlantic	69.0	5.2	8.2	10.7	6.8	0.1
South Atlantic	89.4	2.3	7.3	0.8	0.2	–
Midwest	73.3	13.1	6.2	6.0	1.3	0.1
West	80.3	0.6	2.9	13.2	1.8	1.2
All Sections	71.2	6.9	8.3	8.6	4.7	0.3
	All Oilburners up to 3.0 gph					
All Sections	68.3	7.0	8.6	9.6	5.4	1.1

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[13] Private communication: to D. W. Locklin, Battelle-Columbus, from Margaret Mantho, Fueloil & Oil Heat, May, 1972. Similar data were published in Reference 4.

Table A-4. Average Age of Oil Burners in Use, by Type[4]

	High Pressure					
	Conventional	Shell Head	Retention Head	Low Pressure	Rotary	Vaporizing
	Years					
New England	13.1	9.5	4.1	14.4	16.8	–
Mid-Atlantic	12.4	8.9	4.2	16.2	17.7	15.6
South Atlantic	10.1	7.0	3.0	19.3	–	13.7
Midwest	14.1	8.8	3.7	17.8	17.8	17.0
West	12.7	7.0	3.7	16.6	–	16.7
All Sections	12.6	8.7	3.9	16.5	17.5	15.9

Table A-5. Types of Central Oilheating Equipment in Use, by System Type[4]

			Forced Hot Water		Steam	
	Furnaces	Gravity Hot Water	With Tankless Coil	Without Tankless Coil	With Tankless Coil	Without Tankless Coil
			Percent of Total			
New England	35.6	2.4	39.4	2.2	17.1	3.3
Mid-Atlantic	36.3	2.7	36.9	9.0	9.2	5.9
South Atlantic	74.1	1.5	12.9	4.8	1.5	5.2
Midwest	70.9	0.8	6.9	6.8	12.0	2.6
West	91.4	–	1.7	5.5	0.5	0.9
All Sections	51.9	1.9	25.5	6.5	10.0	4.2

Table A-6. Average Age of Central Oilheating Equipment in Use, by System Type[4]

	Furnaces	Boilers	Combined Boilers/Furnaces	Burners
		Years		
New England	14.9	18.0	16.9	11.9
Mid-Atlantic	14.7	17.4	16.4	12.4
South Atlantic	11.1	17.1	12.5	9.5
Midwest	14.1	17.0	14.9	13.0
West	13.0	16.5	13.3	12.8
All Sections	13.8	17.5	15.6	12.2

Table A-7. Combustion Chambers of Oil Burners in Use, by Type[14]

	Firing Rate					
	Below 1.0 gph			1.0 to 3.0 gph		
	Refractory Brick	Ceramic Fiber	Steel	Refractory Brick	Ceramic Fiber	Steel
	Percent of Total					
New England	61	19	20	78	12	10
Mid-Atlantic	66	22	12	84	12	4
South Atlantic	44	13	43	63	7	30
Midwest	61	25	14	61	31	8
West	38	27	35	66	10	24
All Sections	60	22	18	74	16	10

[14] "Combustion Chambers by Types", Fueloil & Oil Heat, Vol. 31, No. 5, March 1972, p. 94.

Table A-8. Oil Burners in Use With Solenoid Valves[4]

	Firing Rate	
	Below 1.0 gph	1.0 to 3.0 gph
	Percent of Total	
New England	9	21
Mid-Atlantic	25	34
South Atlantic	34	35
Midwest	34	35
West	6	4
All Sections	23	29

APPENDIX B

BACKGROUND DATA ON COMMERCIAL-INDUSTRIAL BOILER POPULATION

This appendix presents information on the profile of commercial and industrial boilers, with distributions and trends by boiler type, capacity, and burner and fuel types, which were used in selecting the equipment mix for this investigation.

Boiler industry statistics frequently combine commercial and industrial boilers; the distinction is sometimes based on application and sometimes on size. (For purposes of this investigation, the "commercial" range was defined as sizes between 10 and 300 boiler horsepower, or approximately 0.3 to 10 million Btu/hr output.) Thus, to discriminate in considerable detail on aspects which are common to the two major boiler size categories, both commercial boilers and industrial boilers up to 500 million Btu/hr output are included in the profile presented in this appendix.

BOILER SURVEY

As an initial step in the survey of commercial-industrial boilers, available data were reviewed. These data were obtained from

1. "Systematic Study of Air Pollution from Intermediate-Size Fossil-Fuel Combustion Equipment", J. R. Ehrenfeld, et al., Final Report on Contract No. EPA 22-69-85, July, 1971.
2. "Stationary Watertube Steam and Hot Water Generator Sales, 1970", American Boiler Manufacturer's Association (ABMA).
3. *Fueloil & Oil Heat*
4. Various other sources.

Although these publications contained data on the boiler population and/or sales, data were not available with the detailed distributions of size, boiler type, fuel type, etc., as needed for this study.

Therefore, through the assistance of ABMA, a questionnaire was submitted to members of the ABMA Air Pollution Committee and a number of other key persons in the boiler industry. Additionally, the same questionnaire was submitted to the members of the API SS-5 Task Force. The questionnaire was designed to solicit percentage estimates of the present population of boilers and of boiler sales trends over the last 40 years by pertinent boiler, burner, and fuel characteristics.

Summary of Boiler Survey

Tables B-1 through B-8 summarize the replies to the questionnaire and the boiler population study; they represent composite data from the various replies and are presented here as the "best estimate" of the population as determined from the various sources. The summary is organized in tables as follows:

Current Equipment Population

Table B-1. By Boiler Type

Table B-2. By Fuel Capability (including oil type)

Table B-3. By Burner Type (for oil and coal)

Trends in Sales (by Years for '30, '50, '70, and Forecast for '90)

Table B-4. By Boiler Type

Table B-5. By Fuel Capability (including oil type)

Table B-6. By Burner Type (for oil and coal)

Annual Usage Factor (or Load Factor)

Table B-7. By Boiler Application

Boiler and Burner Life Expectancy

Table B-8. By Boiler Type and Burner Type (for oil and coal).

General observations on the field population statistics are as follows:

- A high portion of smaller boilers are packaged boilers, while most of the larger boilers are field erected units.
- Fire-tube and cast-iron boilers are more prevalent in the smaller sizes and water-tube boilers are more prevalent in the larger sizes.
- In the commercial-boiler size range, fire-tube boilers are the most numerous type, with cast iron being next in popularity. In the smaller commercial sizes (10-50 hp), firebox boilers are the most numerous of the fire-tube types but are about equal in number with packaged Scotch boilers in the larger sizes (100-300 hp).
- Smaller boilers mostly fire a single fuel (gas or No. 2 fuel oil), with an increasing percentage of duel-fuel boilers used for the larger sizes.
- For oil-fired boilers, the smaller boilers are generally fired with No. 2 fuel oil; the grade of fuel fired generally increases with boiler size.
- Pressure atomizers are most common for small, oil-fired boilers, rotary and air atomizers for intermediate-size boilers, and steam atomizers for larger boilers.
- Coal-fired boilers are rare in the commercial size range.

Boiler Selection for Phase II

Based on the estimates of the present boiler population presented in Tables B-1 through B-3, a selection of six boilers was made for inclusion in the Phase II studies. This selection was discussed in Chapter II.

Table B-1. Population
Breakdown by Boiler Types (Percentage Basis)
All Commercial-Industrial Boilers Now in Service in U.S.

RATED CAPACITY, SIZE RANGE		Commercial			Industrial			
	10^6 Btu/hr or 10^3 lb stm/hr				10-16	17-100	101-250	251-500
	Boiler Horsepower	10-50	51-100	101-300	301-500			
WATER TUBE								
Industrial Type > 10^4 # Steam/hr		▨	▨	▨	(22)	(79)	(100)	(100)
Packaged		▨	▨	▨	15	55	25	0.5
Field erected		▨	▨	▨	7	24	75	99.5
Commercial Type < 10^4 # Steam/hr		(6)	(8)	(5)	▨	▨	▨	▨
Coil		2	3	2	▨	▨	▨	▨
Firebox		1	1	1	▨	▨	▨	▨
Other		3	4	2	▨	▨	▨	▨
FIRE TUBE								
Packaged Scotch		15	20	30	30	10	▨	▨
Firebox		25	25	30	25	10	▨	▨
Vertical		1	0.5	nil	▨	▨	▨	▨
Horizontal Return Tubular (HRT)		5	10	15	20	1	▨	▨
Misc. (Locomotive type, etc.)		2	3	5	3	nil	▨	▨
CAST IRON		45	33	15	▨	▨	▨	▨
MISC. (Tubeless, etc.)		1	0.5	nil	▨	▨	▨	▨
TOTAL COMMERCIAL-INDUSTRIAL BOILERS		100%	100%	100%	100%	100%	100%	

Table B-2. Population
Breakdown by Fuel Capability (Percentage Basis)
All Commercial-Industrial Boilers Now in Service

		Commercial			Industrial			
RATED CAPACITY, SIZE RANGE	10^6 Btu/hr or 10^3 lb stm/hr				10-16	17-100	101-250	251-500
	Boiler Horsepower	10-50	51-100	101-300	301-500			
FUELS								
Oil Only		42	42	40	35	35	30	22
Gas Only		50	50	50	45	35	22	22
Coal Only		2	1	1	3	10	18	22
Oil & Gas and Gas & Oil		5	6	8	16	18	26	23
Oil & Coal and Coal & Oil		▨	▨	▨	▨	▨	0.5	3
Gas & Coal and Coal & Gas		▨	▨	▨	▨	▨	0.5	3
Misc. Fuels (alone or with alternate fuels)		1	1	1	1	2	3	5
Total		100%	100%	100%	100%	100%	100%	100%
OIL								
Distillate, No. 2		95	85	50	10	2	2	2
Resid		(5)	(15)	(50)	(90)	(98)	(98)	(98)
No. 4 and Light No. 5 (No preheat)		4.5	14	30	20	2	nil	nil
Heavy No. 5 and No. 6 (Preheated)		0.5	1	20	70	96	98	98
Total Oil		100%	100%	100%	100%	100%	100%	100%

Table B-3. Population
Breakdown by Burner Type (Percentage Basis)
All Commercial-Industrial Boilers Now in Service in U.S.

		Commercial			Industrial			
RATED CAPACITY, SIZE RANGE	10^6 Btu/hr or 10^3 lb stm/hr				10-16	17-100	101-250	251-500
	Boiler Horsepower	10-50	51-100	101-300	301-500			
OIL BURNERS (approx. gph)		3-15	15-30	30-90	90-150	150-900	900-2250	2250-4500
Air Atomizing		15	35	40	40	15	5	1
Steam Atomizing		▨	▨	▨	20	70	85	94
Pressure or Mechanical Atomizing		70	25	20	10	10	10	5
Rotary		15	40	40	30	5	▨	▨
Total Oil		100%	100%	100%	100%	100%	100%	100%
COAL BURNERS (approx. lb/hr)		33-160	160-330	330-1000	1000-1600	1600-10,000	10,000-25,000	25,000-50,000
Spreader		60	60	55	60	45	45	20
Underfeed		15	15	20	15	15	15	nil
Overfeed		5	5	5	5	5	5	nil
Pulverized		▨	▨	▨	▨	▨	15	65
Other		20	20	20	20	35	20	15
Total Coal		100%	100%	100%	100%	100%	100%	100%

Table B-4. Estimated Trends of Boiler Types (Percentage Basis)
All Commercial-Industrial Boilers Installed in Years Noted

RATED CAPACITY, SIZE RANGE	Commercial												Industrial															
10^6 Btu/hr or 10^3 lb stm/hr													10-16				17-100				101-250				251-500			
Boiler Horsepower	10-50				51-100				101-300				301-500															
	'30	'50	'70	'90	'30	'50	'70	'90	'30	'50	'70	'90	'30	'50	'70	'90	'30	'50	'70	'90	'30	'50	'70	'90	'30	'50	'70	'90
WATER TUBE																												
Industrial Type > 10^4 # Steam/Hr	—	—	—	—	—	—	—	—	—	—	—	—	(25)	(17)	(19)	(20)	(94)	(97)	(94)	(90)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)
Packaged	—	—	—	—	—	—	—	—	—	—	—	—	0	2	18	20	0	8	80	89	0	0	80	90	0	0	1	20
Field erected	—	—	—	—	—	—	—	—	—	—	—	—	25	15	1	0	94	89	14	1	100	100	20	10	100	100	99	80
Commercial Type < 10^4 # Steam/Hr	(13)	(15)	(16)	(21)	(13)	(16)	(16)	(12)	(5)	(11)	(10)	(14)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Coil	nil	2	3	5	nil	3	5	4	nil	3	4	5	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Firebox	8	5	3	1	8	5	3	1	3	3	4	5	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Other	5	8	10	15	5	8	8	7	2	5	2	4	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
FIRE-TUBE																												
Packaged Scotch	nil	10	11	10	1	14	22	26	2	21	41	40	nil	35	40	45	nil	2	5	9	—	—	—	—	—	—	—	—
Firebox	6	11	18	20	20	15	17	23	20	30	35	30	20	40	40	35	1	1	1	1	—	—	—	—	—	—	—	—
Vertical	5	6	6	6	3	5	3	2	5	2	nil	nil	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Horizontal Return Tubular (HRT)	5	1	nil	nil	5	2	nil	nil	60	25	1	nil	50	5	nil	nil	5	4	nil	nil	—	—	—	—	—	—	—	—
Misc. (Locomotive type, etc.)	8	5	3	2	5	1	1	1	8	5	2	nil	5	3	1	nil	nil	nil	nil	nil	—	—	—	—	—	—	—	—
CAST IRON	60	50	45	40	50	45	40	36	nil	5	10	15	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
MISC (TUBELESS, ETC)	3	2	1	1	3	2	1	nil	nil	1	1	1	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
TOTAL COMMERCIAL-INDUSTRIAL BOILERS	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
			%				%				%				%				%				%				%	

Table B-5. Estimated Trends by Fuel Capability (Percentage Basis)
All Commercial-Industrial Boilers Installed in Years Noted,
Including Conversions

RATED CAPACITY, SIZE RANGE	Commercial												Industrial															
10^6 Btu/hr or 10^3 lb stm/hr													10-16				17-100				101-250				251-500			
Boiler Horsepower	10-50				51-100				101-300				301-500															
	'30	'50	'70	'90	'30	'50	'70	'90	'30	'50	'70	'90	'30	'50	'70	'90	'30	'50	'70	'90	'30	'50	'70	'90	'30	'50	'70	'90
FUEL CAPABILITY																												
Oil Only	20	40	30	15	10	30	25	15	10	40	30	30	17	43	30	30	13	30	30	25	5	20	24	20	5	15	20	10
Gas Only	10	30	45	50	10	30	38	50	5	25	30	30	5	20	30	30	10	30	30	25	5	20	24	20	5	15	20	10
Coal Only	65	20	5	nil	75	15	5	nil	80	10	5	nil	75	10	5	nil	75	30	5	nil	90	38	15	nil	90	60	20	10
Oil & Gas and Gas & Oil	nil	5	18	25	nil	10	30	25	nil	20	30	30	nil	25	30	30	nil	5	30	35	nil	10	25	40	nil	5	20	30
Oil & Coal and Coal & Oil	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	nil	5	5	5	nil	3	10	20
Gas & Coal and Coal & Gas	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	nil	5	5	5	nil	2	10	20
Misc. fuels (alone or with alternate fuels)	5	5	2	10	5	5	2	1	5	5	5	10	3	2	5	10	2	5	5	15	nil	2	2	10	nil	nil	nil	nil
Total	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
		%				%				%				%				%				%				%		
OIL																												
Distillate, No. 2	40	50	70	100	20	30	40	70	10	10	20	40	5	2	10	30	nil	nil	10	20	nil	nil	5	10	nil	nil	5	10
Resid	(60)	(50)	(30)	(nil)	(80)	(70)	(60)	(30)	(90)	(90)	(80)	(60)	(95)	(98)	(90)	(70)	(100)	(100)	(90)	(80)	(100)	(100)	(95)	(90)	(100)	(100)	(95)	(90)
No. 4 & Light No. 5 (No preheat)	40	40	25	nil	50	50	50	30	30	40	30	5	20	23	10	nil	nil	5	nil	nil	nil	nil	nil	nil	nil	nil	nil	nil
Heavy No. 5 & No. 6 (Preheated)	20	10	5	nil	30	20	10	nil	60	50	50	55	75	75	80	70	100	95	90	80	100	100	95	90	100	100	95	90
Total Oil	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
		%				%				%				%				%				%				%		

Table B-6. Estimated Trends by Burner Type (Percentage Basis)
All Commercial-Industrial Boilers Installed in Years Noted,
Including Conversions

RATED CAPACITY, SIZE RANGE		Commercial												Industrial															
	10^6 Btu/hr or 10^3 lb stm/hr													10-16				17-100				101-250				251-500			
	Boiler Horsepower	10-50				51-100				101-300				301-500															
		'30	'50	'70	'90	'30	'50	'70	'90	'30	'50	'70	'90	'30	'50	'70	'90	'30	'50	'70	'90	'30	'50	'70	'90	'30	'50	'70	'90
OIL BURNERS																													
Air Atomizing		10	15	15	15	15	20	30	30	20	30	55	60	10	20	35	40	5	3	2	1	2	1	nil	nil	2	1	nil	nil
Steam Atomizing		▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	30	30	35	40	75	80	88	90	93	94	95	95	93	94	95	95
Pressure or Mechanical Atomizing		70	75	85	85	55	60	65	70	50	40	40	40	25	20	20	20	15	14	10	9	5	5	5	5	5	5	5	5
Rotary		20	10	nil	nil	30	20	5	nil	30	30	5	nil	35	30	10	nil	5	3	nil	nil	▨	▨	▨	▨	▨	▨	▨	▨
Total Oil		100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
			%				%				%				%				%				%				%		
COAL BURNER																													
Spreader		nil	nil	nil	nil	nil	nil	nil	nil	nil	5	5	nil	5	10	5	nil	15	50	50	nil	15	40	40	nil	15	30	20	nil
Underfeed		5	90	90	nil	45	90	90	nil	75	85	85	nil	75	75	85	90	50	35	35	85	50	30	20	20	40	20	10	10
Overfeed		nil	5	5	nil	5	5	5	nil	20	5	5	nil	15	10	5	5	30	10	10	10	25	15	15	15	20	15	10	10
Pulverized		▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	5	10	20	60	20	30	55	75
Other		95	5	5	nil	50	5	5	nil	5	5	5	nil	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Total Coal		100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
			%				%				%				%				%				%				%		

Table B-7. Typical Annual Usage Factor (or Load Factor)
For Commercial-Industrial Boilers
For Various Applications

$$\text{USAGE FACTOR} = \frac{\text{ACTUAL FUEL USED PER YEAR X 100}}{\text{FUEL USAGE FOR YEAR AT CONSTANT FULL LOAD OPERATION}}$$

		Commercial			Industrial			
RATED CAPACITY, SIZE RANGE	10^6 Btu/hr or 10^3 lb stm/hr				10-16	17-100	101-250	251-500
	Boiler Horsepower	10-50	51-100	101-300	301-500			
APPLICATION		%	%	%	%	%	%	
Commercial Heating		50	50	50	50	60	▨	▨
Commercial Processing (Laundry, etc.)		80	80	80	80	80	80	80
Industrial Heating Only		60	60	60	60	60	60	60
Industrial Processing Only		85	85	88	85	85	90	90
General Industrial Use (Heating, Processing, Power)		▨	▨	▨	▨	85	90	90
Industrial Power		▨	▨	▨	▨	▨	95	95
Utility Power		▨	▨	▨	85	90	95	95

Table B-8. Boiler and Burner Life Expectancy

A. Boiler Life Expectancy, Average

Boiler Type	Years
Water Tube	
Industrial type	
Packaged	30
Field erected	45
Commercial type	
Coil	20
Firebox	25
Other	25
Fire Tube	
Packaged Scotch	20
Firebox	25
Vertical	10
Horizontal return tubular	40
Misc.	10-20
Cast Iron	40
Misc.	30

B. Burner Life Expectancy, Average

Burner Type	Years
Oil Burners	
Air Atomizing	20
Steam Atomizing	30
Pressure/Mechanical Atomizing	15
Rotary	20
Coal Burners	
Spreader	20
Underfeed	15
Overfeed	15
Pulverized	18
Other	15

APPENDIX C

FUEL ANALYSES

Residential Fuels

Table C-1 lists properties of the No. 2 oils fired in residential units for the Phase II investigation. The reference fuel for firing in the residential units (designated RR) was a high-quality hydrotreated fuel.

Table C-2 reports results of chemical analyses for C, H, and N contents of the fuels fired in the residential units.

Commercial Fuels

Table C-3 lists the generally reported properties for the fuel oils fired in the commercial boilers. These include fuel grades Nos. 2, 4, 5, and 6.

The reference fuel for firing in the commercial boilers (designated CR) was a low sulfur residual fuel typical of the 1.0 percent sulfur residual oils being marketed to the East Coast in March, 1972. It was purchased from a fuel oil supplier located in Connecticut.

Table C-4 reports results of chemical analyses for C, H, and N contents of the fuel oils fired in the commercial boilers.

Table C-1. Properties of Fuels Fired in Residential Units[a]

Fuel Fired in Unit	Gravity, API at 60 F	Kinematic Viscosity at 100 F, cs	Flash Point, F	Carbon Residue, Ramsbottom (last 10%), %	Sulfur, %	Aniline Point, %	Diesel Index[b]	ASTM Distillation IBP, F	10%, F	50%, F	90%, F	End Point, F	Recovery, %
23	34.2	2.23	150	0.23	0.19	133	45.5	356	398	490	578	632	99.0
23.1	31.7	2.42	152	0.24	0.17	130	41.2	356	412	498	592	644	99.0
23.2	31.0	2.23	144	0.22	0.15	122	37.8	344	406	490	588	640	99.0
24	32.3	2.20	144	0.23	0.27	124	40.1	344	396	490	586	644	99.0
24.1	34.4	2.47	148	0.14	0.16	140	48.2	366	418	500	582	634	99.0
24.2	30.6	2.19	138	0.25	0.17	119	36.4	342	394	486	588	640	99.0
25	34.1	2.45	154	0.16	0.11	139	47.4	354	416	498	586	634	99.0
25.1	34.2	2.31	150	0.15	0.14	139	47.5	366	414	496	582	630	99.0
25.2	34.8	2.17	158	0.15	0.16	140	48.7	368	416	484	558	614	99.0
26	33.8	2.41	150	0.19	0.17	139	47.0	360	416	494	582	634	99.0
26.1	34.1	2.42	152	0.12	0.14	141	48.1	372	414	500	582	630	99.0
26.2	34.3	3.12	154	0.16	0.14	139	47.7	368	414	502	588	636	39.0
27	31.1	2.45	152	0.23	0.24	129	40.1	370	412	504	586	642	99.0
28	32.7	2.39	156	0.22	0.18	132	43.2	360	408	492	578	634	99.0
29	33.2	2.54	156	0.21	0.17	135	44.8	368	416	502	590	642	99.0
30	34.0	2.59	154	0.18	0.10	142	48.3	364	416	510	592	640	99.0
31	30.9	2.46	152	0.24	0.20	133	41.1	358	412	506	604	656	99.0
32	30.6	2.44	156	0.23	0.16	124	37.9	370	424	510	604	656	99.0
33	32.2	2.42	148	0.24	0.20	129	41.5	358	416	504	590	642	99.0
34	36.9	2.34	160	0.14	0.19	150	55.4	368	414	490	578	630	99.0
35	33.6	1.82	152	0.28	0.24	118	39.6	346	392	468	550	588	99.0
RR[c]	34.7	2.71	142	0.15	0.05	148	51.4	354	418	504	602	640	99.0

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[a] Analyses by E. W. Saybolt and Company.

[b] Diesel index = $\frac{\text{Aniline point in F} \times \text{API gravity}}{100}$

[c] Reference fuel — high-quality hydrotreated fuel.

Table C-2. Chemical Analyses of Fuels Fired in Residential Units[a]

Fuel Fired in Unit	Weight Percent		
	C[b]	H[b]	N[c]
23	87.0	12.8	0.006
23.1	86.9	12.5	0.006
23.2	87.4	12.4	0.007
24	87.5	12.4	0.008
24.1	87.4	12.3	0.011
24.2	86.7	12.2	0.009
25	87.0	12.7	0.006
25.1	86.9	13.1	0.003
25.2	86.7	13.2	0.003
26	86.6	12.7	0.007
26.1	87.1	12.0	0.011
26.2	86.3	13.2	0.005
27	87.2	12.3	0.010
28	86.3	12.5	0.006
29	87.1	12.8	0.005
30	84.6	12.5	0.005
31	84.2	11.8	0.009
32	87.4	12.6	0.008
33	87.2	12.8	0.007
34	85.9	13.4	0.003
35	87.2	12.6	0.007
RR[d]	87.0	13.0	0.005

[a] Analyses by Battelle-Columbus.

[b] Pregl method.

[c] Kjeldahl method.

[d] Reference fuel — a high-quality hydrotreated fuel.

Table C-3. Properties of Fuels Fired in Commercial Boilers[a]

Fuel Fired in Boiler	Fuel Grade No.	Gravity, API at 60 F (D-287)	Viscosity, at 100 F, SSU (D-445)	Flash Point, F (D-93)	Carbon Residue Ramsbottom, % (D-524)	Ash, % (D-482)	Sulfur, % (D-2622)	Nitrogen (Kjeldahl), % (C-93)	Aniline Point, F (D-611)	ASTM Distillation (D-86)						Metals[b]		
										IBP, F	10%, F	50%, F	90%, F	End Point, F	Recovery, %	V, ppm	Ni, ppm	Na, ppm
C2001 & C2002	2	34.6	34.5	145	0.07	0.001	0.27	0.0084	145	336	398	489	586	630	98.0	<1.0	<0.1	<5
C2002	4	23.5	101.7	186	3.18	0.019	1.59	0.17	–	376	502	671	(75% at 700 F max)[c]		–	130	23	<5
C2003	2	34.8	35.0	153	0.07	<0.005	0.16	0.0078	153	357	419	498	592	630	98.0	<1.0	<0.1	<5
C2003	6	17.3	2746	176	9.66	0.062	2.19	0.37	–	362	482	677	(60% at 685 F max)[c]		–	320	74	46
C2004	2	36.4	34.9	157	0.04	<0.005	0.23	0.0113	157	366	417	494	580	520	98.0	<1.0	<0.1	<5
C2004	5	16.6	291	265	7.47	0.021	1.93	0.29	–	400	485	657	(68% at 682 F max)[c]		–	120	41	<5
C2005	2	35.4	35.0	159	0.20	<0.005	0.38	0.0124	159	364	417	494	587	638	98.0	<1.0	<0.1	<5
C2005	6	14.7	3982	224	8.44	0.019	1.67	0.33	–	332	560	660	(70% at 680 F max)[c]		–	89	36	23
C2006	2	36.2	34.9	163	0.06	<0.005	0.18	0.0086	163	380	429	496	584	629	98.0	<1.0	<0.1	<5
C2006	6	16.9	3053	199	6.78	0.017	1.13	0.31	–	328	510	660	(70% at 685 F max)[c]		–	54	24	32
CR[d]	–	23.5	313	205	5.49	0.032	0.99	0.22	–	368	507	677	(78% at 695 F max)[c]		–	170	40	<5

[a] Analyses by American Oil Company

[b] Emission spectroscopy, accuracy ±35 percent

[c] Cracked

[d] Reference fuel for commercial boilers was 1.0 percent sulfur residual fuel oil currently being marketed in Connecticut

Table C-4. Chemical Analyses of Fuels Fired in Commercial Boilers[a]

Fuel Fired in Boiler	Fuel Grade	Weight Percent		
		C[b]	H[b]	N[c]
C2001 & C2002	2	86.1	12.8	0.004
C2002	4	85.0	11.8	0.15
C2003	2	85.8	12.9	0.010
C2003	6	85.2	11.6	0.36
C2004	2	86.9	13.1	0.010
C2004	5	86.0	10.9	0.28
C2005	2	86.8	13.1	0.010
C2005	6	86.8	11.1	0.31
C2006	2	87.1	13.0	0.007
C2006	6	86.0	11.1	0.30
CR[d]	–	86.3	12.5	0.22

[a] Analyses by Battelle-Columbus.

[b] Pregl method.

[c] Kjeldahl method.

[d] Reference fuel for commercial boilers was a 1.0 percent sulfur residual-fuel oil currently being marketed in Connecticut.

APPENDIX D

DETAILS OF FIELD PROCEDURES

RESIDENTIAL UNITS

Prior to setting up the monitoring equipment in the field, each homeowner was visited by a Battelle staff member in advance of the scheduled arrival of the field team. During this visit, the heating unit was examined for accessibility, space requirements, and material needs for rerouting the flue pipe to accommodate the particulate sampling.

When the field team arrived to begin measurements, the monitoring instruments were set up and recalibrated, and stack changes were made to permit installing a test section of duct (needed for particulate sampling) in the stack. The gaseous sampling trains were set up and the instruments checked out. Stack velocities were measured with an S-type Pitot tube, stack pressures and temperatures were measured, and flue-gas flow rate and excess air were calculated. After making the as-found run, the fuel line was broken and the fuel rate was determined volumetrically by connecting the pump suction line to a calibrated container and measuring fuel consumption over a convenient time interval.*

Measurements

Measurements were made of the following gases and stack emissions under various conditions of operation:

- CO_2
- O_2
- CO
- Hydrocarbons (total)
- NO_x and NO
- Particulate loading.

In addition to these measurements, the combustion conditions normally observed by servicemen were measured. These conditions included: draft (over-fire and stack) and flue-gas temperature (at the particulate sampling point which was several feet from the breeching) – plus smoke, CO_2, and O_2 as measured by standard field-type instruments. Details of instrumentation and measurement procedures are given in Appendixes E and F.

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*Measuring fuel consumption required breaking the fuel line. Thus, some air may have entered the fuel line, causing the cutoff to become somewhat more sluggish than normally expected for subsequent tuned and reference-fuel runs.

Conditions Investigated

Emissions from residential units were monitored under the following sets of conditions:

- Cyclic and varied-air runs
  - The as-found condition, A
  - A tuned condition, T
  - Firing a No. 2 hydrotreated reference fuel in the tuned condition, R
- Cyclic runs only
  - Follow-up checks (Units 23 to 26).

Cyclic Runs. Cyclic runs refer to measurements taken at a fixed air setting during operation on a 10-minute-on and 20-minute-off cycle, as controlled by a timer overriding the thermostat. For the cyclic runs, gaseous-emission measurements were made for the entire period, including both the on and off portion of the cycles. Particulate measurements were started at the beginning of the second or third cycle and measured during each 10-minute firing portion of four or five additional cycles. A total of 50 to 60 minutes of firing time (about 3 hours' elapsed time) was required for the particulate sampling to accumulate sufficient material for accurate weighing.

Varied Air Runs. Varied air runs refer to measurements made during steady-state operation of the unit to investigate the effect on emissions of excess-air setting. Gaseous emissions and smoke were measured as the excess air adjustment was varied over the range from full open to approximately a No. 5 to 7 smoke. The varied air runs were made with the house fuel in the as-found condition and with the house and reference fuels for the tuned condition.

As-Found Condition. The initial measurements on the heating unit were made in the "as-found" condition, i.e., no servicing or changes were made except for the rerouting of the flue pipe. Measurements were made during both cyclic and varied air runs.

Tuned Condition. Following the test run in the "as-found" condition, the serviceman cleaned and tuned the burner. This was not an "eyeball" adjustment, but was intended to be a tuning that a skilled serviceman would achieve with normal procedures of good practice with the benefit of instrument readings of draft, CO_2, and smoke. The following steps were included in the serviceman's procedure to establish the tuned conditions:

- Cleaning and adjusting the electrodes
- Cleaning the blast tube and blower wheel
- Cleaning or replacing the nozzle (even by a different size or spray pattern if it were better suited to the installation)
- Cleaning or replacing the oil filter

- Simple sealing of air leaks at inspection door, around blast tube, or in other easily accessible location
- Change in draft-regulator setting (replaced regulator when necessary)
- Change in combustion air adjustment.

The following items, being major repairs or modernization requiring special charges to the homeowner, were *not included* in the tuning procedure.

- Replacement of the combustion chamber or liner
- Sealing of air leaks that would require disassembly of the boiler or furnace jacket.

Replacement of the combustion head generally was not done. However, the burner for Unit 27 was intended to include a flame-retention combustion head which apparently had been removed. To return this unit to its normal operating condition, a flame-retention head was installed during the tuning.

The field team developed a rough CO_2-smoke curve as part of defining the well-tuned conditions. The air adjustment was then made just off the "knuckle" of this curve. The instructions for adjusting to the tuned condition consisted of these steps:

(1) Compare the CO_2 level in the stack with that obtained in sampling by traversing above the fire using a simple averaging procedure. An appreciable difference between stack and over-fire CO_2 is indicative of air infiltration through leaks; easily accessible leaks are to be repaired.

(2) Establish a smoke-CO_2 curve by use of the continuous CO_2 reading and the Bacharach smoke spot reading (with only enough points to define the general shape, and particularly the location of the "knuckle").

(3) If No. 1 or less Bacharach smoke can be achieved with air adjustment alone, adjust the burner to the maximum CO_2 for No. 1 smoke, but allow a cushion no nearer the "knuckle" than 0.5 to 1.0 percent CO_2. (It would be expected that a well-tuned burner should operate with at least 8 percent CO_2.)

(4) If Step (3) cannot be accomplished to reach a No. 1 smoke, carry out any of the specific tuning steps listed above to achieve that performance, or approach it as closely as possible. In this procedure, first priority should be given to reducing smoke level to at least No. 2, and second priority to maintaining high CO_2 (with 0.5 to 1.0 percent cushion from the "knuckle"). The smoke-CO_2 curve should be repeated to define the burner performance and to locate the desired setting for the tuned test run.

All the residential units in the Phase II program were tuned according to the above tuning steps; adjustments for each unit are shown in Table D-1. Following the tuning, gaseous and particulate emissions and smoke were measured for the "tuned" condition while firing the house fuel.

Reference Fuel Condition. After completing the tests for the as-found and tuned conditions, each residential unit was operated on a reference fuel, a high-quality No. 2 hydrotreated fuel. The purpose of the reference fuel measurements was to provide a baseline in comparing the variety of burner units on a common fuel basis and, thus, to remove the effect of randomness in the quality of house fuels. Gaseous emissions and smoke were measured while firing the reference fuel. In addition, particulate emissions were measured for Units 23 to 26.

Follow-Up Checks. To examine the effect of seasonal operation, four installations (Units 23 to 26) were selected for visits at three times during the course of the heating season – an initial measurement series plus two follow-up checks. The initial measurements were made in mid-December, the first follow-up in mid-February, and the second follow-up the last week in April. For the first follow-up, gaseous emissions were measured for the as-found condition using both the house fuel and the reference fuel. Similar gaseous emission measurements were made during the second follow-up and, in addition, particulate emissions were measured while firing the reference fuel for comparison with the particulate measurements made during the initial visit.

These four burners were equipped with operating time clocks and cycle counters to record operating experience between the first and last visits.

COMMERCIAL BOILERS

Although the instrumentation techniques and the emission measurements used for the commercial boilers were similar to those employed for the residential units, the conditions under which the measurements were made were quite different. In addition, SO_2 emissions were measured for the commercial boilers.

The commercial boilers were all investigated in the as-found condition, i.e., no cleaning or other servicing of the boiler was done prior to testing. The exhaust stack from the breeching through the sampling section was replaced with new stack on all units except Unit C2006. For this unit the particulate sampling was done from the roof and it was not economically feasible to replace the entire stack; however, a short section of stack was replaced with a section containing particulate sampling ports.

The commercial measurements were conducted in late spring, 1972 (March 20 through June 8), near the end of the heating season. Visual inspection of the units showed the normal quantities of soot and ash one would expect to accumulate over a typical heating season. (Unit C2003 was a new boiler that had only been fired briefly as a part of the manufacturer's checkout operation. Hence, it was essentially clean.)

Gaseous emissions and smoke measurements were obtained for several excess air settings at each of four loads and for several fuels to yield a fairly complete picture of the various operating parameters.

Table D-1. Information on Condition and Tuning of Residential Units

Unit	Size,[a] gph	Atomizing Nozzle				Normal Cleaning & Electrode Adjustment	Other Steps	Remarks[b]
		Cleaned	Replaced	Pressure, psi				
				As-Found	Tuned			
23[c]	1.35		X	100	100	X	–	Good condition; delay valve not working properly
24[c]	1.00		X	91	100	X	Replaced fuel pump	Average condition
25	1.35	X		100	100	X	Replaced fuel pump filter; heat exchanger baffle plates cleaned	Good condition; 447 gallons of fuel oil delivered between initial visit and first follow-up; stirred up sediment in tank and created nozzle clogging problems
26	1.75		X	100	100	X	Replaced strainer and line filter; installed check valve in fuel line	Good condition
27	1.35	X		110	100	X	Installed new flame retention head	Average condition; nozzle 1 month old
28[c]	1.00		X	95	100	X	Replaced strainer; increased nozzle size to 1.35 gph	Average condition; winds gusting to 65 mph during tuned and reference runs
29	0.75		X	90	100	X	Replaced strainer; soot cleaner used in cleaning heat exchanger	Average condition; unit had a No. 9 smoke in spite of servicing only 3 days earlier
30	0.60		X	88	100	X	Replaced fuel pump, strainer, and two line filters; increased nozzle size to 0.75 gph	Poor condition; original nozzle had been drilled by homeowner
31[c]	1.50		X	100	100	X	Replaced strainer	Good condition
32[c]	1.00		X	99	100	X	Replaced line filter	Poor condition; occasional puff, possibly due to air leak in very old fuel line
33[c]	0.85		X	106	90	X	Replaced strainer; resealed door and burner assembly	Very poor condition
34	0.75		X	80	90	X	Replaced line filter	Average condition
35	1.00		X	100	100	X	–	Good condition

[a] Nozzle size, as found. Replacement nozzles were same size except as noted.

[b] Serviceman's estimate of condition.

[c] Owner has service contract, thus unit probably received an annual cleanup and tuning.

The four load levels at which emission data were obtained for commercial boilers were:

R – rated load

H – a high load for normal operation (selected as 80 percent of rated load)

M – an intermediate load

L – normal low-fire setting.

Boiler C-2001 was fired with a burner having a fixed firing rate and therefore was only operated at three loads: 100, 82, and 61 percent. The different loads were obtained by changing the nozzle size.

For the oil-fired boilers, 12 percent CO_2 was used at the baseline excess-air condition (after discussions with the ABMA Commercial-Industrial Air Pollution Committee). Gaseous emission measurements were made at several excess air levels, generally between 9 and 14 percent CO_2. For gas-fired runs, 9 to 10 percent CO_2 was used as the baseline, representing an excess air level typical of normal boiler operation. Because particulate measurements required extensive sampling times (approximately 80 minutes at each load setting), particulate emissions were measured for only one excess-air level (12 percent CO_2 for oil firing and 9 or 10 percent CO_2 for gas firing) at one or two loads for each fuel fired in each boiler.

To assure the attainment of steady-state conditions when changing load or excess air, the boilers were operated at the new setting for 30 minutes before particulate sampling was begun.

Each boiler (except C-2001) was fired with four different fuels: the typical house fuel, an additional fuel oil ranging from No. 2 through No. 6 grades, a 1-percent sulfur reference residual oil, and natural gas. A sample of each fuel oil was obtained for analysis of its physical properties and chemical composition.

APPENDIX E

SAMPLING AND ANALYTICAL PROCEDURES FOR GASEOUS EMISSIONS

Sampling

Selection of installations with adequate space and accessibility made it possible to sample the gaseous emissions from stacks directly through sampling probes into the monitoring equipment (avoiding grab-bag sampling techniques). Direct sampling with the shortest possible lines minimized losses by condensation, reaction, and/or adsorption.

A schematic drawing of the sampling train used in monitoring gaseous emissions from both residential and commercial units is shown in Figure E-1.

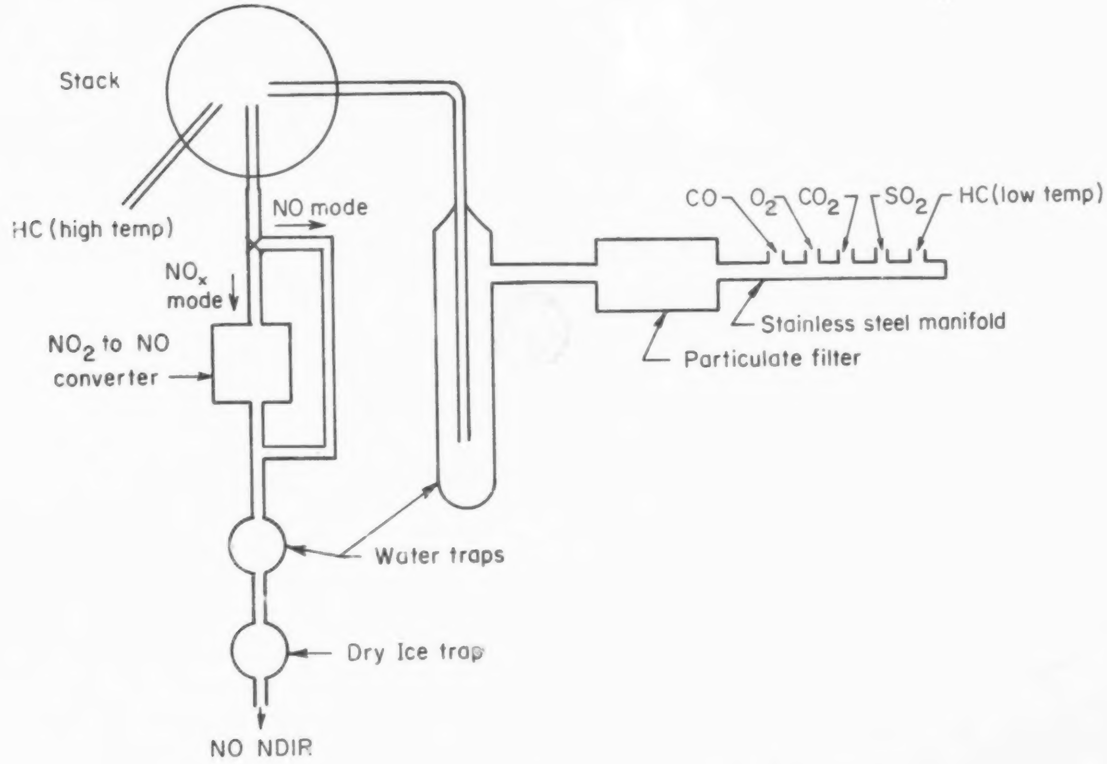

Stack
HC (high temp)
NO mode
NO_x mode
NO_2 to NO converter
Water traps
Dry Ice trap
NO NDIR
CO
O_2
CO_2
SO_2
HC (low temp)
Stainless steel manifold
Particulate filter

Figure E-1. Sampling Trains for Gaseous Emissions

Two parallel sampling trains were normally used – one for CO_2, O_2, CO, SO_2, and total hydrocarbons (when using the low-temperature analyzer) and a second for NO and NO_x. The first train included a Pyrex ice-water trap (with a side arm sufficiently long to reach the center of the largest flue pipe), a small glass-wool particulate trap, and a stainless steel manifold. The second train included a 1/4-in. heated Teflon line, NO_2 to NO converter, ice-cooled water trap, and a Dry Ice-cooled water trap. When the high-temperature hydrocarbon analyzer was used, a third probe was employed which consisted of a 1/4-in. heated Teflon line connected directly to the analyzer.

Analytical Methods

It is generally recognized that monitoring equipment with 100 percent reliability is still lacking, especially for field measurements. Therefore, special care was taken in checking out, tuning, and calibrating all instruments prior to each run. Zero and appropriate upscale span gases were used for calibration.

The monitoring techniques used in the field on this program are listed in Table E-1. The choice of techniques was based primarily on the emission range anticipated, interference-correction requirements, and ease of use in the field.

Table E-1. Gaseous Emission Instrumentation Used in Field Survey

Pollutant	Instrument	Range[a]	Principle of Operation	Comments
CO	Beckman Model 215A	0-1250	NDIR	Continuous, portable; water and CO_2 interference can be accommodated
Total HC	Beckman Model 109A	0-120,000	Flame ionization	Continuous, fast response, portable
	Beckman Model 402	0-120,000	Flame ionization	Selectable elevated temperature sampling line and oven
NO	Beckman Model 315L	0-750	NDIR	Continuous, portable; water and CO_2 interference can be accommodated
NO_x	Faristor	0-2500	Electrochemical (dry)	Continuous, fast response, portable; SO_2 interference can be accommodated
	Beckman Model 315L	0-750	NDIR with NO_2 to NO converter	Continuous, portable, water and CO_2 interference can be accommodated; CO interference in converter cannot be accommodated
SO_2	Faristor	0-2500	Electrochemical (dry)	Continuous, fast response, portable; no NO_2 interference
CO_2	Beckman Model 215A	0-20%	NDIR	Continuous, portable; water interference can be accommodated
O_2	Beckman Model 715	0-25%	Amperometric	Continuous, portable

(a) Ppm except as noted.

Carbon Monoxide. Carbon monoxide was continuously monitored by nondispersive infrared using a Beckman Model 215A analyzer. The instrument has two ranges, 0 to 250 and 0 to 1250 ppm. The sensitivity is 0.5 percent of full scale with an accuracy of ±1 percent.

Hydrocarbons. Total hydrocarbons were measured by flame ionization using two Beckman analyzers – Model 109A and Model 402. The operation of the two analyzers is basically the same, the primary difference being that the Model 402 utilizes a selectable elevated-temperature sampling line and analyzer oven. Sampling at elevated temperatures (200 to 400 F) minimizes the loss of higher molecular-weight hydrocarbons. Both analyzers are usable over a wide range of concentrations and have excellent response time and sensitivity. The most sensitive range obtainable is 0 to 10 ppm carbon, while the least sensitive range is about 0 to 120,000 ppm carbon.

Nitrogen Oxide. Three techniques were used to continuously measure the nitrogen oxide concentrations.

- NO by NDIR analyzer
- NO_x by NDIR + converter
- NO_x by an electrochemical analyzer.

The nondispersive infrared (NDIR) analyzer, a Beckman Model 315L, has three ranges (0-150, 0-450, and 0-750 ppm). The unit in actuality measures nitric oxide (NO). However, when used in conjunction with a NO_2 to NO converter, it can also be used for measuring NO_x.

The NO_2 to NO thermal converter is a 6-ft-long coil of 1/8-in.-diameter No. 316 stainless steel tubing which is resistance heated to 650-700 C. A bypass valve on the converter permits rapid switching between NO (bypassing the converter) and NO_x modes. The internal surface of the converter heater coil is stabilized when delivered; however, periodic reconditioning is necessary. This is accomplished by passing NO or NO_2/air through the converter for approximately 15 minutes while in the NO_x mode.

The Faristor, an electrochemical analyzer, operates on the principle of a fuel cell. When sample gas is passed through the detector, an electrochemical process within the detector generates an electrical signal proportional to the NO_x concentration in the gas sample. This signal is amplified and then displayed on a meter having a 0 to 100 linear scale. Two range settings are possible – 0 to 500 ppm for the low range and 0 to 2500 ppm for the high range.

Sulfur Dioxide. The Faristor electrochemical cell was also used to measure SO_2. The Series NS-200 SO_2/Nitrogen Oxide Analyzer is bimodular, using two Faristor plug-in detectors, Type N76H2 for measuring NO_x and Type S64H2 for measuring SO_2. Two analog outputs are available on the Faristor permitting simultaneous monitoring of both gases.

Carbon Dioxide. Nondispersive infrared was also used in monitoring CO_2. The instrument, a Beckman Model 215A, has two ranges (0 to 5 percent and 0 to 20 percent CO_2 by volume). The sensitivity is 0.5 percent of full scale with an accuracy of ±2 percent.

Oxygen. The Beckman Model 715 Process Oxygen Analyzer was used to continuously monitor gaseous oxygen. The analyzer has ranges of 0 to 5 percent and 0 to 25 percent oxygen. Accuracy is ±1 percent of full scale at a given sample temperature and ±6 percent of full scale for sample temperature variations within the temperature range of 32 to 110 F.

The amperometric oxygen sensor contains a gold cathode and silver anode. The two electrodes are separately mounted within the PVC body and are electrically connected by a potassium chloride electrolyte. A gas-permeable Teflon membrane separates the electrodes from the process sample and fits firmly against the gold cathode. Oxygen from the sample diffuses through the membrane and is reduced at the gold cathode. The resultant electrical current flow between the electrodes is proportional to the partial pressure of oxygen in the sample.

Response Times

Response times (to 90 percent for step changes of gaseous composition) for the various gases and instruments (including the sampling probe and train) were as follows:

Gas	Analysis Technique	90 Percent Response Time, seconds
CO	NDIR	63
Total HC	Flame-ionization detector	3
NO	NDIR	60
SO_2	Electrochemical cell	72
CO_2	NDIR	57
O_2	Amperometric	65

APPENDIX F

SAMPLING AND ANALYTICAL PROCEDURES FOR PARTICULATE AND SMOKE AND DETAILED PARTICULATE DATA

Particulate Sampling

The particulate sampling rig used in this investigation was the EPA sampling train[2,8], with modifications for oil burner emissions measurements. Figure F-1 shows the particulate sampling train. For the residential runs, the sampling probes used were a combination nozzle and probe, 15 inches long, extending out of the top of the heated chamber of the sampling train. The cyclone included in the EPA rig was not used and the probe was connected directly to the filter. For the commercial runs, a 36-inch combination probe and nozzle was used and the cyclone was used. The rest of the train was as shown in Figure F-1, and the procedures of operation (except probe and impinger washing) were those specified by EPA.

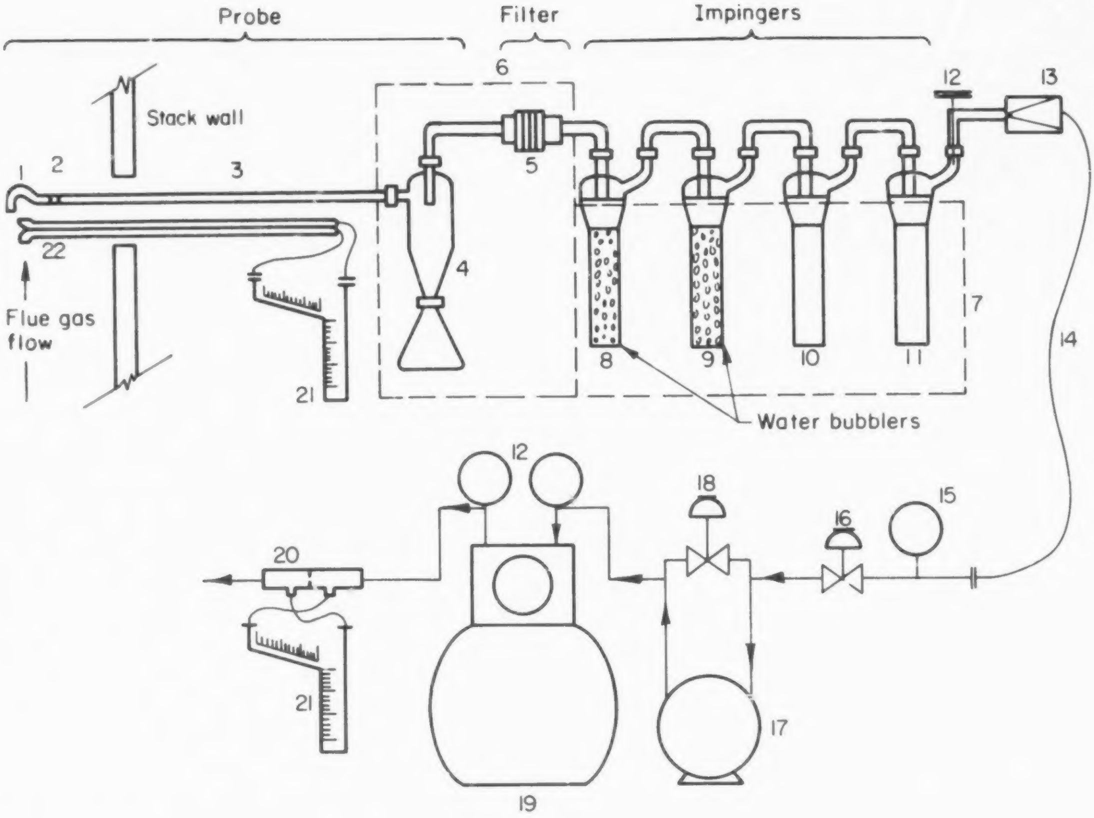
Velocities in the stacks were measured with a S-type Pitot tube. As the firing of the residential units was relatively constant from cycle to cycle, S-type Pitot tube measurements were made during the cycle preceding the beginning of sampling. For sampling from commercial boilers, the S-type Pitot tube and thermocouple were attached to the probe and positioned adjacent to the sampling nozzle.

For residential units, it was not always possible to get reliable velocity pressure readings, as some flue gas velocities were so low that the Pitot tube velocity pressures were in the range of 0.002 to 0.005 inch of water. Hence, to insure isokinetic sampling, the fuel-oil firing rate was measured, excess air was determined, and the flue-gas volume and average velocity were calculated and compared with the Pitot tube measurements. (For the as-found runs, the fuel rate was measured after the run as a check on isokinetic sampling. For the tuned and reference-fuel runs, this measurement was made before the run.)

Traversing was not done during particulate sampling from residential units. In cases where the velocity profile across the duct was relatively uniform, the sample was collected by isokinetic sampling at a velocity about equal to the average velocity. Sampling at the average velocity was not possible where velocity profiles were not uniform.

For particulate sampling from commercial boilers, two traverses were made at 90° angles. Sampling was done at four points on each traverse.

The sampling rig was operated in accord with the EPA recommendation, i.e., the filter was kept at a temperature between 230 and 250 F and the impingers were immersed in an ice bath. The first two impingers contained 100 ml of double-distilled water each, the third impinger was initially dry, and the fourth impinger contained about 175 grams of Drierite. Moisture was collected in the impingers and in the Drierite. The volume of dry flue gas sampled for the particulate collection run was measured by a dry gas meter.


Probe
Filter
Impingers
6
12
13
Stack wall
1
2
3
5
4
22
Flue gas flow
7
14
21
8
9
10
11
Water bubblers
12
18
15
16
20
21
17
19

1. Stainless steel, buttonhook-type probe tip
2. Stainless steel coupling
3. Probe body, 5/8-inch OD, medium-wall Pyrex tube logarithmically wound with 25 feet 26 ga. nickel-chromium wire
4. Cyclone and flask (not used for residential units)
5. Fritted-glass filter holder
6. Electrically heated enclosed box
7. Ice bath containing four impingers connected in series
8. The Greenburg-Smith type impinger with tip removal
9. Second impinger with tip
10. Third impinger with tip removed
11. Fourth impinger with tip removed and containing approximately 175 grams of accurately weighed dry silica gel
12. Pressure gauge
13. Check valve
14. Flexible-rubber vacuum tubing
15. Vacuum gauge
16. Needle valve
17. Leakless vacuum pump
18. By-pass valve
19. Dry-gas meter
20. Calibrated orifice
21. Draft gauge
22. S-type pitot tube

Figure F-1. EPA Particulate Sampling Train

Before the sampler was put in operation, it was leak checked to see that all the joints were tight. The nozzle was plugged with a rubber stopper and 10 inches of vacuum was drawn on the system. With this vacuum, no more than 0.02 cfm leakage was permitted; checks showed that actual leakage usually was much less than this value.

Silver membrane filters were used.* The filter for the residential unit was a 3-inch-diameter silver membrane with a pore size of 0.8 micron. Because of the higher particulate loadings expected when firing heavier fuels in the commercial boilers, a 5-inch-diameter silver membrane filter with a pore size of 0.8 micron was used for those runs.

For the residential units, particulate sampling was initiated just before the start of the 10-minute "on" cycle and was stopped just after the "on" cycle was completed. During the 20-minute "off" cycle, there was no particulate sampling. Particulate was sampled for six firing cycles to collect sufficient particulate for weighing.

PARTICULATE ANALYSIS

Moisture Content of Flue Gas

After the particulate run was completed, the moisture content of the sampled gas was determined by weighing the Drierite to determine the gain in weight and measuring the amount of moisture in each of the impingers. These measurements were used to calculate the total quantity of water in the sample volume and the moisture content of the flue gas.

Particulate Loading

The silver membrane filters were dried and the tare weight obtained before the run was started. After the run, the filter was removed, dried, desiccated, and weighed to obtain the quantity of material collected on the filter.

As a result of earlier particulate sampling at Battelle-Columbus, questions have arisen as to whether the EPA procedure washes all particulate out of the probe. Hence, the particulate sampling for this project was designed to permit samples to be obtained by both the EPA method and a modified-EPA method (MEPA) which included more thorough washing of the probe and impingers.**

Table F-1 shows the steps involved in washing the probe and impingers and storing the samples for later drying and weighing. The washing which generated the samples in Containers 2B and 5B were the additional washings not required by EPA.

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*This is a departure from the glass-fiber filters specified by EPA[2], but silver filters are superior for detailed chemical analysis and are not hydroscopic, a characteristic of glass-fiber filters.

**The modified method is similar to the procedure used in Phase I (prior to publication of the EPA procedure).

Table F-1. Procedures for Recovery of Particulate Catches
Sample Recovery From Particulate Sampler.

Container No. 1. Remove the filter from its holder, place in this container, and seal.

Container No. 2A. Place loose particulate matter and acetone washings from all sample-exposed surfaces prior to the filter (probe and front half of filter) in this container and seal. Use a razor blade, brush, or rubber policeman to loosen adhering particles.

Container No. 2B.[a] Wash the probe and the front half of the filter holder successively with:

1. Methylene chloride
2. Water
3. Acetone.

Place the washings in this container and seal.

Container No. 3. Measure the volume of water from the first three impingers and place the water in this container. Place water rinsings of all sample-exposed surfaces between the filter and fourth impinger in this container prior to sealing.

Container No. 4. Transfer the silica gel from the fourth impinger to the original container and seal. Use a rubber policeman as an aid in removing silica gel from the impinger.

Container No. 5A. Thoroughly rinse all sample-exposed surfaces between the filter and fourth impinger with acetone (but do not wash fourth impinger), place the washings in this container, and seal.

Container No. 5B.[a] Thoroughly rinse all sample-exposed surfaces between the filter and fourth impinger successively with methylene chloride and acetone, place the washings in this container, and seal.

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[a] These steps are not included in the EPA procedure but were included in this investigation.

Figures F-2 and F-3 show the drying procedure followed for each container obtained in the washing procedure. The weights recorded as "EPA-Probe" and "EPA-Impinger" correspond to the conventional EPA procedure for obtaining particulate weights. The weights recorded as "MEPA-Probe" and "MEPA-Impinger" include the material obtained by the additional washing; they were not a part of the conventional EPA procedure.

In each step, washing and drying, the above procedures were designed to follow the EPA procedure first and then to add any additional steps recommended by the Battelle staff. Hence, the additional steps in no way interfered with the EPA procedure.

RESULTS

Tables F-2 and F-3 present summaries of the results obtained using the above procedures for both EPA procedures (EPA) and modified EPA procedures (MEPA). These tables include:

- Probe catch
- Filter catch
- Impinger catch

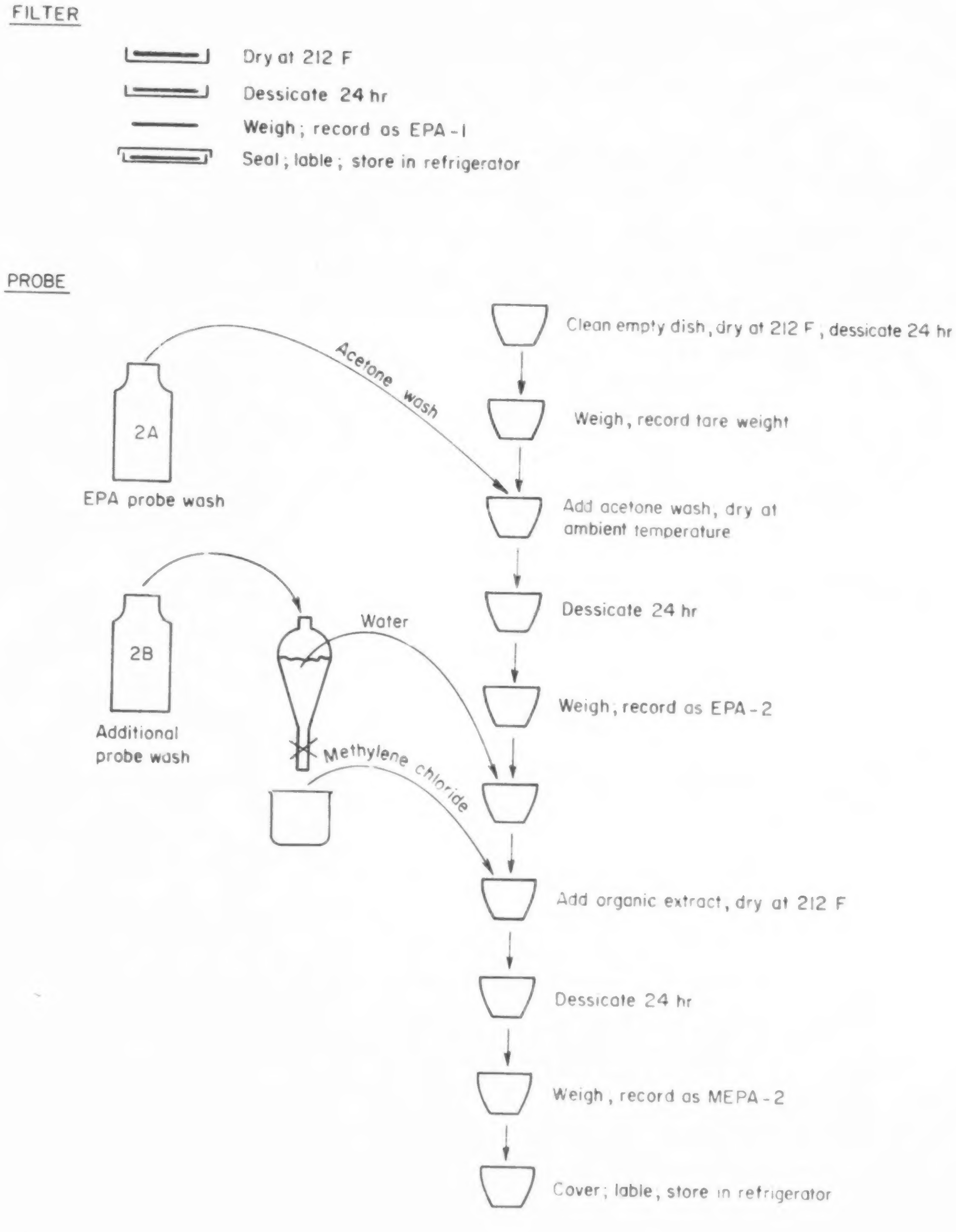
FILTER
Dry at 212 F
Dessicate 24 hr
Weigh; record as EPA-1
Seal; lable; store in refrigerator
PROBE
Clean empty dish, dry at 212 F, dessicate 24 hr
Acetone wash
Weigh, record tare weight
2A
EPA probe wash
Add acetone wash, dry at ambient temperature
Dessicate 24 hr
Water
2B
Weigh; record as EPA-2
Additional probe wash
Methylene chloride
Add organic extract, dry at 212 F
Dessicate 24 hr
Weigh, record as MEPA-2
Cover; lable, store in refrigerator

Figure F-2. Procedures for Drying Filter and Probe Portions of Particulate Samples

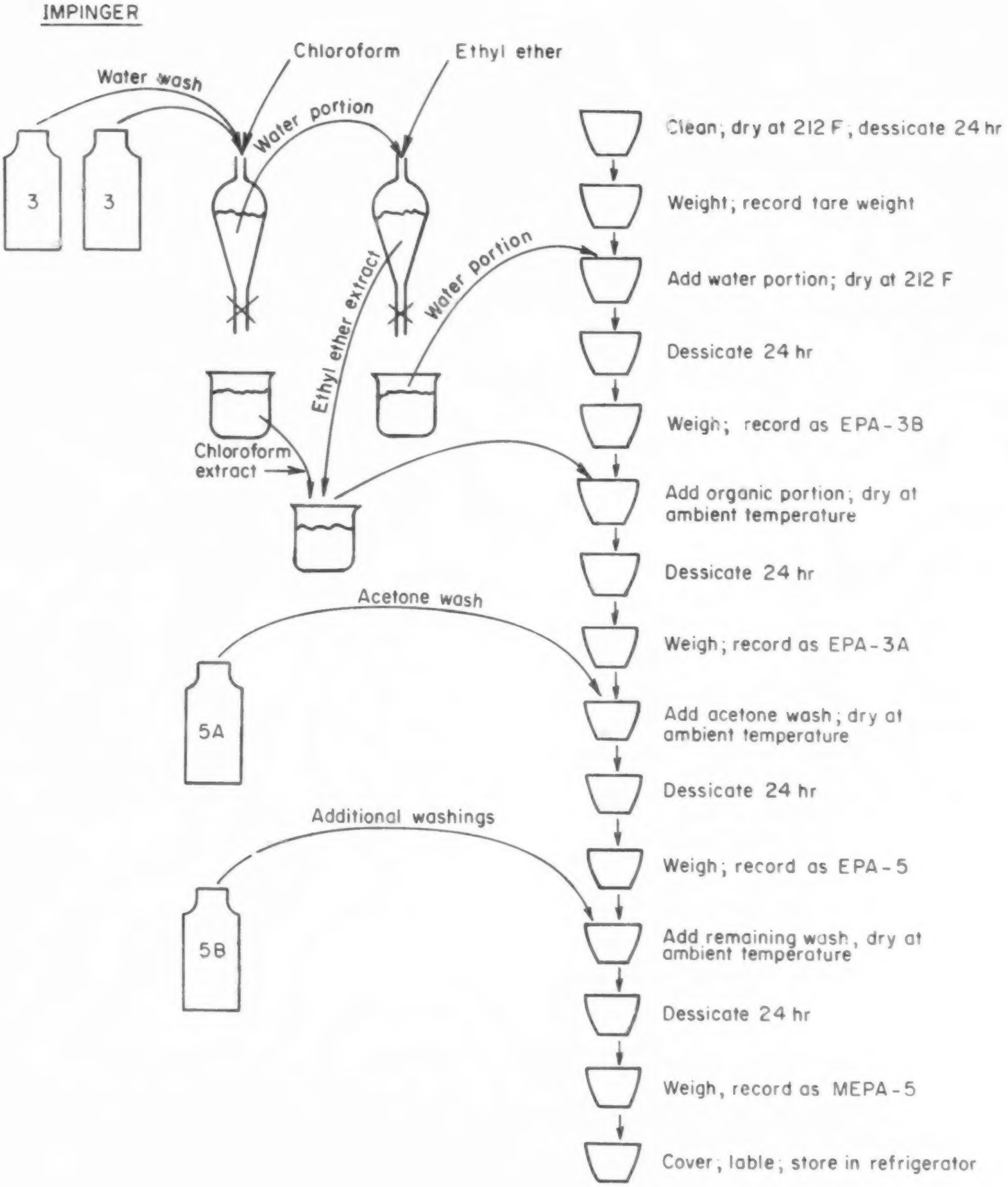
IMPINGER
Chloroform
Ethyl ether
Water wash
Water portion
3
3
Ethyl ether extract
Water portion
Chloroform extract
Acetone wash
5A
Additional washings
5B
Clean; dry at 212 F; dessicate 24 hr
Weight; record tare weight
Add water portion; dry at 212 F
Dessicate 24 hr
Weigh; record as EPA-3B
Add organic portion; dry at ambient temperature
Dessicate 24 hr
Weigh; record as EPA-3A
Add acetone wash; dry at ambient temperature
Dessicate 24 hr
Weigh; record as EPA-5
Add remaining wash, dry at ambient temperature
Dessicate 24 hr
Weigh, record as MEPA-5
Cover; lable; store in refrigerator

Figure F-3. Procedures for Drying Impinger Portions of Particulate Samples

Table F-2. Summary of Particulate Emission Data for Residential Units[a]

Unit	Mass of Particulate Collected, mg					Totals, mg				Percent Filterable		Grain Loading EPA Procedure, mg/sm^3		Emission Factor, lb/1000 gal				Bacharach Smoke No. at 9 Min
	Probe Wash		Filter	Impinger Wash		EPA		MEPA						EPA Procedure		MEPA Procedure		
	EPA	MEPA		EPA	MEPA	Filterable	Total	Filterable	Total	EPA	MEPA	Filterable	Total	Filterable	Total	Filterable	Total	
23A	3.9	9.8	3.1	9.3	11.8	7.0	16.3	12.9	24.7	43	52	5.8	13.5	0.84	1.94	1.55	2.94	0.3
23T	1.6	6.2	1.9	19.1	21.8	3.5	22.6	8.1	29.9	15	27	3.1	19.7	0.40	2.60	0.93	3.44	0.5
23R	1.3	5.2	2.6	15.6	17.0	3.9	19.5	7.8	24.8	20	31	3.2	16.1	0.44	2.22	0.88	2.82	0.4
23.2R	2.0	10.1	6.1	21.6	23.9	8.1	29.7	16.2	32.0	27	51	6.3	23.0	0.91	3.33	1.82	3.59	0.0
24A	1.3	5.3	3.1	10.8	12.9	4.4	15.2	8.4	21.3	29	39	3.2	11.0	0.61	2.09	1.17	2.93	0.4
24T	3.7	9.4	11.0	29.2	30.5	14.7	43.9	20.4	50.9	33	40	13.7	41.0	2.03	6.05	2.82	7.02	0.7
24R	1.7	9.7	14.4	10.7	17.3	16.1	26.8	24.1	41.4	60	58	12.5	20.9	1.76	2.93	2.64	4.53	0.8
24.2R	8.8	5.1	5.6	20.6	22.9	9.4	30.0	10.7	32.3	31	33	7.7	24.6	1.15	3.97	1.31	4.27	0.7
25A	1.4	5.6	0.4	21.0	21.1	1.8	22.8	6.0	27.1	8	22	1.7	21.0	0.25	3.14	0.83	3.73	1.0
25T	3.4	6.4	1.1	11.3	12.5	4.5	15.8	7.5	20.0	28	38	4.4	15.3	0.58	2.03	0.97	2.57	1.7
25R	3.1	6.8	1.6	9.0	10.5	4.7	13.7	8.4	18.9	34	44	4.4	12.8	0.65	1.89	1.16	2.61	0.9
25.2R	6.3	22.4	67.8	36.5	40.5	74.1	110.6	90.2	114.6	67	79	64.7	96.6	8.21	12.25	9.99	12.69	5.8
26A	1.6	5.8	6.0	26.8	27.7	7.6	34.4	13.8	41.5	22	33	6.1	27.4	1.08	4.91	1.96	[illegible]	0.5
26T	3.9	6.8	4.5	9.7	10.6	8.4	18.1	11.3	21.9	46	52	6.7	14.5	1.06	2.16	1.35	2.61	0.4
26R	2.5	8.2	4.8	12.1	13.0	7.3	19.4	13.0	26.0	38	50	6.0	16.0	0.87	2.32	1.55	3.11	0.5
26.2R	1.9	7.1	3.4	13.6	15.6	5.3	18.9	10.5	20.9	28	50	4.6	16.4	0.65	2.33	1.29	2.58	0.4
27A	2.0	11.0	8.8	27.8	26.6	10.8	38.6	19.8	46.4	28	43	9.3	33.1	1.31	4.70	2.40	5.65	1.0
27T	2.3	11.1	4.5	10.1	16.1	6.8	16.9	15.6	31.7	40	49	5.6	13.9	0.88	2.18	2.02	4.09	0.4
28A	2.1	7.6	8.7	26.5	31.6	10.8	37.3	16.3	47.9	29	34	9.7	33.6	1.90	6.55	2.87	8.41	[illegible]
28T	1.7	6.3	2.1	12.3	18.1	3.8	16.1	8.4	26.5	24	32	3.2	13.5	0.54	2.30	1.19	3.79	0.4
29A	3.3	10.0	2.5	24.9	23.7	5.8	30.7	12.5	36.2	19	35	14.4	76.0	1.91	10.13	4.12	11.95	9.0
29T	2.7	11.5	39.3	23.7	23.8	42.0	65.7	50.8	74.6	64	68	36.3	56.8	5.81	9.09	7.03	10.32	0.5
30A	2.3	6.9	4.8	28.8	29.9	7.1	35.9	11.7	41.6	20	28	5.8	29.5	0.98	4.94	1.62	5.72	0.2
30T	2.0	10.2	5.1	25.1	26.2	7.1	32.2	15.3	41.5	22	37	6.1	27.8	1.10	4.98	2.37	6.42	0.6
31A	2.1	6.2	2.7	26.7	27.1	4.8	31.5	8.9	36.0	15	25	4.6	30.0	0.77	5.05	1.43	5.77	0.0
31T	3.1	7.6	3.7	46.6	44.3	6.8	53.4	11.3	55.6	13	20	9.1	71.2	1.23	9.64	2.04	10.04	0.2
32A	2.6	7.8	3.6	44.0	43.1	6.2	50.2	11.4	54.5	12	21	5.3	42.9	0.98	8.00	1.80	8.63	0.2
32T	2.6	6.7	9.8	31.8	32.6	12.4	44.2	16.5	49.1	28	34	10.5	37.3	1.60	5.71	2.13	6.34	0.1
33A	4.0	14.7	14.4	118.6	106.8	18.4	137.0	29.1	135.9	13	21	15.4	114.3	3.24	24.11	5.12	23.92	1.5
33T	3.7	15.4	11.3	101.4	99.3	15.0	116.4	26.7	126.0	13	21	14.1	109.7	2.83	21.95	5.04	23.76	1.8
34A	2.3	6.3	20.0	32.8	30.8	22.3	55.1	26.3	57.1	40	46	18.9	46.8	2.49	6.15	2.94	6.37	2.7
34T	2.5	6.4	9.2	31.0	29.5	11.7	42.7	15.6	45.1	27	35	10.9	38.9	1.44	5.11	1.92	5.40	1.0
35T	2.8	18.6	2.1	59.4	59.7	4.9	64.3	20.7	80.4	8	26	4.2	55.2	0.61	8.04	2.58	10.05	0.2
35R	1.4	13.7	1.9	39.5	33.9	3.3	42.8	15.6	49.5	8	32	2.9	37.6	0.39	5.09	1.84	5.89	0.2

[a] EPA refers to EPA Procedure specified in Reference 2. MEPA refers to "Modified EPA Procedure" described in text.

Table F-3. Summary of Particulate Emission Data for Commercial Boilers[a]

			Mass of Particulate Collected					Totals, mg				Percent Filterable		Grain Loading, EPA Procedure, mg/sm^3		Emission Factor, lb/1000 gal[b]				Bacharach Smoke No.
			Probe Wash		Filter	Impinger Wash		EPA		MEPA						EPA Procedure		MEPA Procedure		
Boiler	Fuel	Load	EPA	MEPA		EPA	MEPA	Filterable	Total	Filterable	Total	EPA	MEPA	Filterable	Total	Filterable	Total	Filterable	Total	
C2001	No. 2	H	2.4	12.6	5.4	68.9	66.4	7.8	76.7	18.0	84.4	10	21	4.6	45.5	0.5	4.9	1.2	5.4	2.4
C2001	No. 2	L	2.4	11.2	9.2	17.0	20.5	11.6	28.6	20.4	40.9	41	50	9.2	22.7	1.0	2.4	1.8	3.4	2.8
C2001	Gas	H	1.5	6.6	4.2	25.4	27.7	5.7	31.1	10.8	38.5	18	28	2.6	14.2	0.3	1.5	0.6	1.9	0.2
C2002	No. 2	H	4.6	9.0	16.5	23.0	25.6	21.1	44.1	25.5	51.1	48	50	9.6	20.0	1.1	2.2	1.3	2.5	0.6
C2002	No. 4	H	1.6	8.9	34.1	15.4	19.9	35.7	51.1	43.0	62.9	70	68	32.8	46.9	3.7	5.3	4.5	6.5	2.3
C2002	No. 4	L	1.2	10.5	0	55.8	61.1	1.2	57.0	10.5	71.6	2	15	1.4	64.1	0.2	7.2	1.8	9.0	2.8
C2002	CR	H	4.7	12.8	228.9	32.2	36.1	233.6	265.8	241.7	277.8	88	87	103.	117.	11.7	13.3	12.1	13.9	3.0
C2002	Gas	H	3.6	8.9	2.0	21.4	25.5	5.6	27.0	10.9	36.4	21	30	2.4	11.4	0.2	1.1	0.4	1.5	0.1
C2003	No. 2	H	7.8	14.0	6.6	14.1	17.5	14.4	28.5	20.6	38.1	51	54	11.2	22.2	1.2	2.4	1.7	3.2	2.0
C2003	CR	H	95.6	102.8	261.6	24.5	27.2	357.2	381.7	364.4	391.6	94	93	286.	305.	32.9	35.0	33.6	35.9	3.1
C2003	No. 6	H	205.6	225.4	695.3	27.0	30.1	900.9	927.9	920.7	950.8	97	97	722.	744.	87.2	89.9	89.1	92.1	4.2
C2003	No. 6	L	53.1	66.2	95.6	70.9	67.9	148.7	219.6	161.8	229.7	68	70	207.	306	27.0	39.9	29.4	41.7	5.7
C2003	Gas	H	3.7	10.5	0.7	11.6	15.2	4.4	16.0	11.2	26.4	28	42	4.0	14.7	0.4	1.5	1.0	2.5	0.0
C2004	No. 2	H	7.3	14.0	1.9	7.2	9.0	9.2	16.4	15.9	24.9	56	64	9.3	16.6	1.0	1.8	1.7	2.7	0.2
C2004	No. 2	L	2.4	7.1	12.2	42.3	42.0	14.6	56.9	19.3	61.3	26	31	6.5	25.2	0.8	3.0	1.1	3.2	3.4
C2004	CR	H	16.8	23.6	58.3	40.5	40.9	75.1	115.6	81.9	122.8	65	67	67.6	104.	7.7	11.8	8.4	12.5	2.9
C2004	No. 5	H	38.3	48.7	97.4	68.6	66.3	135.7	204.3	146.1	212.4	66	69	134.	202.	16.1	24.3	17.3	25.3	5.0
C2004	Gas	H	1.4	6.9	1.0	4.3	6.2	2.4	6.7	7.9	14.1	36	56	2.2	6.2	0.2	0.6	0.7	1.3	0.0
C2005	No. 2	H	1.3	6.2	4.0	31.8	32.4	5.3	37.1	10.2	42.6	14	24	5.4	37.5	0.6	4.0	1.2	4.6	0.0
C2005	CR	H	2.4	6.3	41.6	23.5	25.7	44.0	67.5	47.9	73.6	65	65	44.6	68.5	5.1	7.8	5.6	8.5	2.5
C2005	No. 6	H	19.7	24.7	76.1	50.4	49.3	95.8	146.2	100.8	150.1	66	67	102.	156.	12.6	19.3	13.3	19.8	3.8
C2005	No. 6	L	6.2	11.8	40.8	50.0	49.2	47.0	97.0	52.6	101.8	48	52	40.9	84.3	5.0	10.3	5.6	10.8	3.4
C2005	Gas	H	1.7	7.1	0.9	13.5	13.7	2.6	16.1	8.0	21.7	16	37	2.7	16.7	0.3	1.6	0.9	2.2	0.1
C2006	No. 2	H	0.8	7.1	6.2	30.8	30.8	7.0	37.8	13.3	44.1	19	30	3.3	17.8	0.4	1.2	0.8	1.4	0.4
C2006	CR	H	22.7	27.6	50.5	29.8	31.6	73.2	103.0	78.1	109.7	71	71	66.6	93.7	7.5	10.6	8.0	11.3	3.4
C2006	No. 6	H	76.1	83.9	93.1	38.3	37.1	169.2	207.5	177.0	214.1	82	83	235.	288	27.8	34.0	29.1	35.1	4.1
C2006	No. 6	L	20.8	22.0	19.5	83.4	67.8	40.3	123.7	41.5	109.3	33	38	73.5	226.	8.6	26.4	8.9	23.3	5.2
C2006	Gas	H	3.4	8.4	4.5	11.8	13.4	7.9	19.7	12.9	26.3	40	49	4.5	11.1	0.5	1.2	0.8	1.6	0.0

[a] EPA refers to EPA Procedure specified in Reference 2. MEPA refers to "Modified EPA Procedure" described in text.

[b] Emission factor for gas firing for this table is lb/(145 x 10^6 Btu), about the same on a Btu basis as lb/1000 gal for oil firing.

- Filterable catch, probe plus filter
- Total catch
- Percent filterable
- Grain loading
- Emission factor
- Smoke number, Bacharach.

The results of Tables F-2 and F-3 show that the revised washing procedure (used in the "modified" EPA method) did wash more material from the probe than was obtained using standard EPA washing procedures. Comparative results obtained by using the two washing procedures are as follows:

	Particulate Emission Factors, lb/1000 gal					
	Filterable			Total		
	EPA	MEPA	Difference	EPA	MEPA	Difference
Average for residential units	1.51	2.43	+0.92	5.88	6.76	+0.88
Average for commercial boilers firing No. 2	0.83	1.35	+0.52	2.74	3.30	+0.56
Average for commercial boilers firing No. 4 CR	9.83	10.57	+0.74	13.00	13.94	+0.94
Average for commercial boilers firing No. 5 and No. 6	26.33	27.53	+1.20	34.87	35.44	+0.57

On the average, sufficient additional particulate was washed from the probe by the extra washings used in the modified procedure to increase emission factors nearly 1.0 lb/1000 gal. The additional washings did not increase the particulate associated with the impinger catch.

Impinger Catch

The filterable fraction of the total particulate catch averaged 28 percent (EPA procedure) or 38 percent (MEPA procedure) for residential units and 54 percent (EPA procedure) or 58 percent (MEPA procedure) for oil-fired boilers. Questions arise as to the composition of the remainder of the total particulate catch – that portion associated with the impinger. The detailed analyses that would be required to determine the exact nature of the impinger catch was not a part of this study. However, some analyses of impinger samples were made during the Phase I study.

Analyses of the impinger samples for C, H, and N accounted for 11 percent of the impinger catch for samples from residential units and 33 percent of the impinger catch for samples from oil-fired commercial boilers. Sulfur analyses were made on impinger samples from the commercial boilers.* These analyses identified sulfur present in quantities that represented 15 to 99 percent of the impinger catch. Assuming that the sulfur is present as SO_3 (possibly in H_2SO_4 or sulfates), the quantities of sulfur compounds present were calculated to be 38 to 248 percent of the impinger catch. The problem associated with finding SO_3 in quantities greater than the mass of dried particulate illustrates the difficulties encountered in making sense out of impinger catch data. Apparently, large quantities of SO_2 are retained in the impinger solutions and, over a period of time, some of the SO_2 is oxidized to SO_3[15]. It may have been that some SO_2 was driven off those portions of the samples used for the particulate weight determinations during the drying operation. However, during the interval about 4 months before the sulfur analyses were made on the remaining portions of the samples, additional SO_2 may have oxidized. Thus, the latter analyses gave sulfur quantities higher than the total particulate from the former analyses.

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*One-half of the impinger catch was dried (within about 2 months of the sampling) to obtain the weight of the particulate catch. The remaining one-half of the impinger catch was analyzed for total sulfur about 5 months after the sampling.

SMOKE SAMPLING TECHNIQUES

Two techniques for sampling smoke were used. Use of the standard Bacharach hand-pump smoke meter and ASTM Procedure D2156-65[7] was the primary method of smoke spot sampling. The ports for the gaseous measurements were used as sampling locations for smoke measurements. If conditions suggested erroneous readings due to greatly disturbed air flow, the sample was taken through the particulate sampling port. However, in most cases the gaseous ports were adequate.

For the residential units, Bacharach smoke readings were made at the 1-minute, 5-minute, and 9-minute points of the "on" cycle. As expected, the smoke number usually decreased as the cycle proceeded. The decrease between the 1- and 5-minute points generally was much greater than that between the 5- and 9-minute points.

To enable the field team to monitor the variations in smoke during the cyclic runs, a Von Brand continuous recording smoke meter was used. During a run, the vacuum pump was started 15 seconds prior to ignition. This permitted observation of smoke levels for the air in the stack prior to firing of the burner. Smoke levels were monitored continuously throughout each on-cycle until all evidence of smoke associated with shutdown had ceased. This smoke persisted from 1 second to 30 seconds. The smoke associated with burner startup and shutdown coincided with the CO and HC peaks noted for the gaseous emissions.

A Photovolt reflectometer with tricolor filter was used to obtain numerical reflectance values from the Bacharach smoke spots according to ASTM standard procedures[7]. This provided a means for accurately reading the smoke spot while reducing the possibility of human error caused by inadequate lighting, colored material, or oil on the smoke spot.

An attempt was made to correlate reflectometer readings from the Bacharach smoke spots to similar readings of the Von Brand tape traces. A good correlation was not obtained for the low smoke levels of interest (below about a No. 3 or 4 Bacharach smoke).

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[15] Hillenbrand, L. J., Engdahl, R. B., and Barrett, R. E., "Chemical Composition of Particulate Air Pollutants from Fossil Fuel Combustion Sources", Final Report on EPA Contract EHSD 71-29, March 1, 1973.

APPENDIX K

DETAILS OF EMISSION-FACTOR CALCULATIONS AND CONVERSION FACTORS

Emission factors are commonly defined in terms of the weight of pollutant emissions per unit of fuel input – either weight, volume, or Btu heating value of the fuel. For purposes of this report, emission factors for oil fired equipment are expressed in terms of pounds of pollutant per thousand gallons of fuel oil input, as this is the basis of the published emission factors compiled by EPA[3], and it also is convenient in developing emission inventories.

Calculation of the emission factors requires data on (1) the concentration of the pollutant (e.g., ppm for gaseous pollutants or dust loading in mg/sm^3 for particulate) and (2) the rate of generation of flue gas. This latter quantity may be determined by one of several approaches, depending on data available. Four alternate approaches are feasible, requiring the following information:

(1) Measurement of flue-gas flow rate, plus flue-gas analysis (used where fuel composition and firing rate are unknown)

(2) Measurement of flue-gas flow rate, plus fuel firing rate

(3) Fuel firing rate, plus flue-gas analysis (the most frequently used technique)

(4) Fuel composition (C-H), plus flue-gas analysis.

Of these approaches, the fourth was chosen as being consistently the most accurate for the conditions of the field investigation. This approach is outlined in the following section.

Combustion Calculations

The combustion equation, assuming that all of the sulfur and nitrogen from the fuel appear as SO_2 and NO in the flue gas and that CO and HC in the flue gas are negligible, is

$$\begin{aligned} &CH_E S_F N_G + (1.0 + 0.25E + F + 0.5G + X)O_2 \\ &\quad + [(1.0 + 0.25E + F + 0.5G + X)\ 3.77]N_2 = CO_2 + 0.5E \cdot H_2O \\ &\quad + F \cdot SO_2 + G \cdot NO + X \cdot O_2 \\ &\quad + [(1.0 + 0.25E + F + 0.5G + X)\ 3.77]N_2 \end{aligned}$$

where E = ratio of hydrogen atoms to carbon atoms in the fuel,

$$E = \frac{12.01 \cdot (\text{wt\% H in fuel})}{1.008 \cdot (\text{wt\% C in fuel})}$$

F = ratio of sulfur atoms to carbon atoms in the fuel,

$$F = \frac{12.01 \cdot (\text{wt\%S in fuel})}{32.06 \cdot (\text{wt\%C in fuel})}$$

and G = ratio of nitrogen atoms to carbon atoms in the fuel

$$G = \frac{12.01 \cdot (\text{wt\%N in fuel})}{14.008\ (\text{wt\%C in fuel})}$$

and X = ratio of percent O_2 to percent CO_2 in flue gas.

From this equation, a predicted CO_2 and O_2 concentration for the dry flue gas can be expressed as

$$CO_2 \text{ in flue gas, percent} = \frac{100}{4.77 + 4.77X + 0.94E + 4.77F + 2.89G}$$

$$O_2 \text{ in flue gas, percent} = \frac{100X}{4.77 + 4.77X + 0.94E + 4.77F + 2.89G}$$

Solving each of these equations for X gives

$$X \text{ (based on } CO_2 \text{ measurement)} = \frac{100 - CO_2\ [4.77 + 0.94E + 4.77F + 2.89G]}{4.77 \cdot CO_2}$$

$$X \text{ (based on } O_2 \text{ measurement)} = \frac{O_2\ [4.77 + 0.94E + 4.77F + 2.89G]}{100 - (4.77 \cdot O_2)}$$

where CO_2 and O_2 are the CO_2 and O_2 concentrations in the flue gas. Excess air (EA) in terms of the above combustion equation is defined as

$$EA\text{, percent} = \frac{100 \cdot X}{1.0 + 0.25E + F + 0.5G}$$

Thus, excess air can be calculated either based on CO_2 or O_2 readings from the flue-gas analysis as

$$EA_{CO_2}\text{, percent} = \frac{100 \cdot X_{CO_2}}{1.0 + 0.25E + F + 0.5G}$$

or

$$EA_{O_2}\text{, percent} = \frac{100 \cdot X_{O_2}}{1.0 + 0.25E + F + 0.5G}$$

Values for excess air calculated by these two routes did not always agree for this investigation. (Usually, the difference was small, less than 10 percent). The reliability of the CO_2 and O_2 field measurements were considered and judged to be similar. Thus, an average value was used to define the actual excess air:

$$EA', \text{percent} = \frac{EA_{CO_2} + EA_{O_2}}{2} \quad .$$

Likewise,

$$X' = \frac{X_{CO_2} + X_{O_2}}{2} \quad .$$

The weight (W) of dry flue gas generated in pounds per pound of fuel fired at this average excess air is

$$W = \frac{(1.0 \cdot 44.01)+(F \cdot 64.06)+(G \cdot 30.01)+(X' \cdot 32.0)+[(1.0+0.25E+F+0.5G+X')3.77 \cdot 28.02]}{(12.01)+(E \cdot 1.008)+(F \cdot 32.06)+(G \cdot 14.01)}$$

The volume (V) of dry flue gas generated (standard cubic feet per pound of fuel fired) is

$$V = \frac{W}{0.075} \quad .$$

$V_{12\%\ CO_2}$ and $V_{3\%\ O_2}$ are defined as the volume of dry flue gas generated per pound of fuel fired at 12% CO_2 and at 3% O_2 in the flue gas, respectively.

Emission Factor Calculations, lb/1000 gal

Gaseous emission factors, EF, can now be calculated as

$$EF_a \text{ (lb pollutant/1000 gal fuel)} = \frac{V \cdot PPM \cdot MW \cdot FD}{386 \cdot 1000}$$

where PPM = concentration of pollutant in flue gas (dry)

MW = molecular weight of pollutant

FD = fuel density in lb/gal.

Particulate emission factors, EF′, can be calculated as follows:

$$EF'_a \text{ (lb particulate/1000 gal fuel)} = \frac{V \cdot GL \cdot FD}{15800}$$

where GL = grain loading measured in sampled gas in mg per standard cubic meter (dry at 77 F).

Converting to Other Emission Factor Units

Emission factors in lb/1000 gal can be converted to other units as follows:

Gaseous Emissions.

$$EF_b \text{ (kg pollutant/1000 liter fuel)} = EF_a \cdot 0.1198$$

$$EF_c \text{ (lb pollutant/1000 lb fuel)} = \frac{EF_a}{FD}$$

$$EF_d \text{ (g pollutant/kg fuel)} = EF_c = \frac{EF_a}{FD}$$

$$EF_e \text{ (lb pollutant/}10^6\text{ Btu)} = \frac{EF_a \cdot 1000}{\text{Heating value of fuel (Btu/gal)}}$$

It is sometimes convenient to express emissions in ppm at some standard condition, for example:

$$EF_f \text{ (ppm pollutant at 12\% } CO_2\text{, dry)} = \frac{PPM \cdot V}{V_{12\%\ CO_2}}$$

$$= \frac{EF_a \cdot 386 \cdot 1000}{MW \cdot FD \cdot V_{12\%\ CO_2}}$$

and

$$EF_g \text{ (ppm pollutant at 3\% } O_2\text{, dry)} = \frac{PPM \cdot V}{V_{3\%\ O_2}}$$

$$= \frac{EF_a \cdot 386 \cdot 1000}{MW \cdot FD \cdot V_{3\%\ O_2}}$$

Particulate Emissions. Similarly for particulates, EF_b', EF_c', EF_d', and EF_e' follow from EF_a'. Additional emission factors are sometimes used for particulate emissions as follows:

$$EF_h' \text{ (lb particulate/}10^6\text{ scf flue gas at 12\% } CO_2\text{, dry)}$$

$$= \frac{GL \cdot 1000}{15800} \cdot \frac{V}{V_{12\%\ CO_2}}$$

or

$$= \frac{EF_a' \cdot 1000}{FD \cdot V_{12\%\ CO_2}}$$

and EF_i' (lb particulate/10^6 scf flue gas at 3% O_2 dry)

$$= \frac{GL \cdot 1000}{15{,}800} \cdot \frac{V}{V_{3\%\ O_2}}$$

$$= \frac{EF_a' \cdot 1000}{FD \cdot V_{3\%\ O_2}}$$

Conversion Factors for No. 2 Fuel Oil

For a typical No. 2 fuel oil of 33 degrees API gravity,

FD = 7.17 lb/gal

Heating value = 139,900 Btu/gal

Analysis = 87.0% C
12.6% H
0.17% S
0.007% N

$V_{12\%\ CO_2}$ = 243 cu ft/lb fuel

$V_{3\%\ O_2}$ = 219 cu ft/lb fuel.

Then

EF_c (lb pollutant/1000 lb fuel) $= 0.139 \cdot EF_a$

EF_d (g pollutant/kg fuel) $= 0.139 \cdot EF_a$

EF_c (lb pollutant/10^6 Btu) $= 0.00715 \cdot EF_a$

EF_f (ppm pollutant at 12% CO_2, dry) $= \dfrac{222 \cdot EF_a}{MW}$

EF_g (ppm pollutant at 3% O_2, dry) $= \dfrac{246 \cdot EF_a}{MW}$

EF_h' (lb particulate/10^6 scf flue gas at 12% CO_2, dry) $= 0.574 \cdot EF_a'$

and

EF_i' (lb particulate/10^6 scf flue gas at 3% O_2, dry) $= 0.637 \cdot EF_a'$

Conversion Factors for No. 6 Oil

For a typical No. 6 fuel oil of 15 degrees API gravity,

FD = 8.05 lb/gal

Heating value = 151,200 Btu/gal

Analysis = 86.8% C
11.1% H
1.70% S
0.30% N

$V_{12\%\ CO_2}$ = 243 cu ft/lb fuel

$V_{3\%\ O_2}$ = 214 cu ft/lb fuel

Then

EF_c (lb pollutant/1000 lb fuel) $= 0.124 \cdot EF_a$

EF_d (g pollutant/kg fuel) $= 0.124 \cdot EF_a$

EF_e (lb pollutant/10^6 Btu) $= 0.00661 \cdot EF_a$

EF_f (ppm pollutant at 12% CO_2, dry) $= \frac{197 \cdot EF_a}{MW}$

EF_g (ppm pollutant at 3% O_2, dry) $= \frac{224 \cdot EF_a}{MW}$

EF_h' (lb particulate/10^6 scf flue gas at 12% CO_2, dry) $= 0.511 \cdot EF_a'$

and

EF_i' (lb particulate/10^6 scf flue gas at 3% O_2, dry) $= 0.580 \cdot EF_a'$.

Emission Factor Calculations, Gas Firing

Emission factors can be calculated for gas firing in a similar manner as for oil firing (although other calculation-procedures may be simpler for gas firing, only). For example,

EF_r (lb pollutant/1000 lb fuel) $= \frac{V \cdot PPM \cdot MW}{386 \cdot 1000}$

and

EF_r' (lb particulate/1000 lb fuel) $= \frac{V \cdot GL}{15{,}800}$.

Assuming

Density gas = 0.0458 lb/ft^3, standard conditions

Heating value = 1020 Btu/ft^3

Analysis = 75% C
25% H

$V_{3\%\ O_2}$ = 246 cu ft/lb fuel

Then

$$EF_s \text{ (lb pollutant/}10^6 \text{ cu ft)} = 45.81 \cdot EF_r$$

or

$$= \frac{V \cdot PPM \cdot MW}{8430}$$

likewise,

$$EF_s' \text{ (lb particulate/}10^6 \text{ cu ft)} = \frac{V \cdot GL}{345}$$

and

$$EF_t \text{ (lb pollutant/}10^9 \text{ Btu)} = 44.91 \cdot EF_r$$

or

$$= \frac{V \cdot PPM \cdot MW}{8590}$$

likewise,

$$EF_t' \text{ (lb particulate/}10^9 \text{ Btu)} = \frac{V \cdot GL}{352}$$

and

$$EF_u \text{ (ppm pollutant at 3\% } O_2\text{, dry)} = \frac{EF_r \cdot 386 \cdot 1000}{MW \cdot V_{3\%\ O_2}}$$

$$= \frac{1570 \cdot EF_r}{MW}$$

or

$$= \frac{PPM \cdot V}{246}$$

and

$$EF'_v \text{ (lb particulate/}10^6\text{ scf flue gas at 3\% O}_2\text{, dry)} = \frac{EF_r \cdot 1000}{V_{3\%\ O_2}}$$

$$= 4.065 \cdot EF_r$$

or

$$= \frac{V \cdot GL}{3890}$$

Summary of Conversion Multipliers for Oil Firing

Table K-1 summarizes conversion multipliers for some of the common methods of expressing emission factors.

Table K-1. Multipliers to Convert Emission Factors From Lb/1000 Gal To Other Units

To Obtain Emission Factor in These Units	Multiply Emission Factor in lb/1000 Gal Fuel (EF_a) by	
	No. 2 Oil[a]	No. 6 Oil[b]
Kg /1000 liter fuel	0.1198	0.1198
Lb/1000 lb fuel	0.139	0.124
Gm/kg fuel	0.139	0.124
Lb/10^6 Btu input	0.00715	0.00661
Gaseous pollutants[c]		
ppm at 12% CO_2	$\frac{222}{MW}$	$\frac{197}{MW}$
Ppm at 3% O_2	$\frac{246}{MW}$	$\frac{224}{MW}$
Particulates		
Lb/10^6 scf flue gas at 12% CO_2	0.574	0.511
Lb/10^6 scf flue gas at 3% O_2	0.637	0.580

[a] Typical No. 2 fuel oil having 33 API gravity.

[b] Typical No. 6 fuel oil having 15 API gravity.

[c] MW = molecular weight of pollutant.

APPENDIX L

ERRATA TO PHASE I REPORT

During the interval between the publication of the report on Phase I of this study and the present time, several points were identified where clarification or corrections are in order for information contained in the Phase I report [1]. The following sections discuss these points and identify corrections as necessary.

Wherever Phase I results have been incorporated in this Phase II report, the corrected values have been used.

CO Emission Data

Emission values for CO in the Phase I report (Tables IV-1 and VI-1) are high, as the raw NDIR data were not corrected for CO_2 interference. One percent of CO_2 produces an equivalent output from the CO NDIR as 1.25 ppm CO. Hence, about 10 percent CO_2 produces CO readings that are high by 12.5 ppm. Consequently, CO emission factors tabulated in Tables IV-3 and VI-4 are high by the ratio of CO uncorrected to CO corrected. The CO emission factors for oil-fired residential units and commercial boilers are high by about 2.0 lb/1000 gal.

Table I-3, Emission Factors From Residential Furnaces

The NO_x emission factors reported in Table I-3 for the APCO Research Laboratory studies are incorrect. Correct values are as follows:

Modern burners, Reference 4	Average	16.1
	Range	13.4 - 18.8
Modern burners, Reference 5	Average	12.5
	Range	8.5 - 15.5

Table VI-7, Emission Factors for Gas-Fired Commercial Boilers

Table IV-1. Corrected Emission Factors for Phase I Gas-Fired Commercial Boilers

		Emission Factors, lb/10^6 cu ft, natural gas[a]					
						Particulate	
Unit	Condition	CO	HC	SO_2	NO_x	Filterable	Total
C1004	H	3.6	0.6	40	53	9	19
	M	6.2	0.5	38	40	–	–
	L	2.7	0.6	47	39	3	17
	Mean	4.2	0.6	42	44	6	18

[a] Emission factor in lb/10^9 Btu input.

Nitrogen in Distillate Fuel Oils

Kjeldahl analyses of the No. 2 fuel oils fired in the residential units indicated consistently lower values for fuel nitrogen for the Phase II fuels compared to the Phase I fuels. The Phase II fuel nitrogen analyses were confirmed by a round-robin program, with analysis by five different laboratories. Repeat analyses of two Phase I fuels produced fuel nitrogen levels that were lower than those reported in the Phase I report by a factor of about 5. Hence, it must be concluded that fuel nitrogen analyses of the No. 2 fuel oils fired during Phase I are high by a factor of about 5.

Ratio of NO to NO_2

Measurements of NO_x for the Phase I study indicated that about 22 percent of the NO_x was emitted as NO_2. Phase II measurements, which used improved methods for measuring NO and NO_x emissions, gave a ratio of NO_2 to NO_x of about 0.2. However, there is a possible interference of CO with NO_x measurement when large concentrations of CO are present. When the Phase II data for units emitting less than 100 ppm of CO are considered, the ratio of NO_2 to NO_x is only 0.09. Hence, it is concluded that NO_2 emissions are usually less than 10 percent of the total NO_x for residential furnaces.

APPENDIX M

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